The Post 2006 Initiative:

Final Staff Report

to the Commission

December 2, 2004

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Introduction

The Electric Service Customer Choice and Rate Relief Law of 1997 ("the Restructuring Act") was a massive overhaul of the State of Illinois' policy toward electric utility service. It began a transition toward delivery service unbundling and greater reliance on market forces to determine how electric power and energy would be provided to retail customers. January 1, 2007 marks the statutory end of the Restructuring Act's "transition period." With this milestone on the horizon, the Illinois Commerce Commission ("Commission") commenced the Post 2006 Initiative, chaired by Commissioner Erin O'Connell-Diaz. A series of workshops for interested parties to discuss the many issues associated with the post 2006 era was held during the spring and summer of 2004. This report by the staff of the Commission ("Staff") is based on those workshops. It addresses issues both resolved and unresolved during the workshops.

I. Issues Addressed by the Post 2006 Initiative Working Groups

The Restructuring Act imposed a bundled rate freeze that expires on January 1, 2007.[1] Most Illinois utilities sold or spun off their generating assets and entered into long-term supply contracts that terminate on or around January 1, 2007. Unbundled delivery service customers who currently pay "transition charges" will no longer have to pay these charges as of January 1, 2007. Thus, by January 1, 2007, the Commission must have addressed a host of interrelated questions regarding changes in rates, energy assistance, the state of competition, and how utilities will procure power and energy to meet their continuing service obligations.

Chairman Edward Hurley and Commissioners O'Connell-Diaz, Wright, and Ford decided to tackle these issues in five working groups (Procurement, Rates, Competitive Issues, Utility Service Obligations, and Energy Assistance), each one chaired by a different convener. In May, the five working groups set out to examine an extensive list of issues pertinent to each group. The task for each working group was to achieve consensus on as many substantive issues as possible. Where consensus was not reached on substantive issues, each group was to nonetheless reach consensus on a precise definition of the remaining issues and provide a list of possible resolutions (without attribution). A sixth working group (Implementation) was to be formed if and when it became clear that there would be a need for action by legislative bodies and/or Illinois State agencies. Such a working group was in fact formed in September. The final reports of the working groups (except Implementation, which is still in draft form) are attached in Appendix 1 and provide the foundation for each of the six main sections of this Staff report.

Post 2006 Working Groups

- ***Procurement***
- ***Rates***
- ***Competitive Issues***
- ***Utility Service Obligations***
- ***Energy Assistance***
- ***Implementation***

[1] While the law allows bundled rates to change on or after this date, they cannot change unless approved by the Commission.

II. Purpose of this Report

The purpose of this Staff report is not just to relay what has already been reported by the Post 2006 Initiative working groups; it is to make practical recommendations. As previously noted, the working groups were charged with reaching consensus positions on the various issues. Common ground was found on numerous issues, and identification of common ground is an important first step towards preparing for the post 2006 era. However, where consensus was not reached on substantive issues, action is still required. Thus, Staff has used the consensus reports of the working groups as springboards for writing this report. This report does not attempt to exhaustively address all the discussions of the working groups, but Staff makes recommendations in each of the main issue areas.

The recommendations, herein, are guided by Staff's commitment to the goals of the Public Utilities Act ("PUA"). In particular, while the Restructuring Act envisioned greater reliance on market forces, and charged the Commission "to promote the development of an effectively competitive electricity market that operates efficiently and is equitable to all consumers,"[2] the PUA retains Commission authority to set just and reasonable rates for services that have not yet been determined to be competitive. Thus, while promoting development of competitive markets, the Commission continues to possess a regulatory mandate to ensure "the provision of adequate, efficient, reliable, environmentally safe and least-cost public utility services at prices which accurately reflect the long-term cost of such services and which are equitable to all citizens."[3] After 2006, utilities will still be responsible for providing electricity to consumers, and the Commission must determine how to price that electricity, subject to the limitations and constraints imposed by both legal and economic realities.

As one might gather from Staff's Introduction to the Post 2006 Initiative whitepaper (posted on the Commission's web site on February 19, 2004), Staff's main concern relates to the degree of competition in the retail and wholesale electricity marketplace. Other concerns of Staff involve limitations in the transmission system, and concentration among owners of generation available to Illinois and the potential impacts upon prices for power and energy in the post 2006 era. Among the most urgent matters to be resolved, recognizing that transmission and generation issues are almost entirely beyond the Commission's authority, is how the Commission can work with multi-jurisdictional authorities to best mitigate the risk of experiencing inefficiently high prices in the post 2006 era.

III. Summary of the Report

The remainder of this report is organized around the subjects taken up by the six working groups.

[2] 220 ILCS 5/16-101A (d)
[3] 220 ILCS 5/1-102

In the **Procurement** section, Staff makes several recommendations. Chief among them is the recommendation that the Commission not attempt to mandate any particular procurement method. However, Staff does recommend that for certain utilities, the Commission endorse one of the 12 procurement methods analyzed by the group: the vertical tranche auction. In support of this recommendation, Staff makes use of one of the primary areas of consensus: a list of 18 characteristics that members of the working group agreed would be part of an ideal procurement method. Staff argues that the vertical tranche auction, while not a panacea for all the concerns of Staff and other parties, is expected to come the closest to possessing the majority of those 18 desirable characteristics. For other utilities, more traditional procurement approaches are endorsed. While there are several caveats that accompany Staff's recommendations, Staff believes that its endorsed procurement methods can best achieve five overarching policy goals: mitigation of market structure problems; provision of regulatory certainty; provision of market based prices and rate stability; provision of a straightforward mechanism to convert supply acquisition costs into retail rates using traditional rate design; and provision of a working option by January 2007. A list of Staff's procurement-related recommendations can be found on page 18.

The **Rates** section tackles policy issues surrounding both delivery rates and power and energy rates, uniformity of rates, renewable power and other environmental concerns that can be managed through ratemaking, as well as the regulatory process necessary to address outstanding rates issues for the post 2006 era. From a ratemaking perspective, Staff finds no impediments to procuring electricity through a vertical tranche auction, but makes note of several related ratemaking issues that can and should be addressed in formal rate proceedings. Staff recommends that the Commission ensure a well-considered and orderly implementation of any post 2006 rate changes through the timely use of traditional eleven-month case schedules. A complete list of Staff's recommendations related to rate design can be found on page 30.

The **Competitive Issues** section deals with the apparent lack of competitive options available to residential and other relatively small customers. It examines switching statistics as well as definite and potential factors preventing more wide-scale utilization of unbundled service in Illinois. Nevertheless, Staff argues that it is still too early to determine whether residential electric choice can be viable in Illinois. Such an assessment should wait until some time after the transition period ends. Staff recommends against drastic stimulus measures, such as setting residential rates above the utility's actual cost of service. However, the Commission and the General Assembly should remove barriers to entry where they can be identified. Prospects for larger non-residential competition are significantly better than in the residential market. Interest in delivery services has continued to grow since 1999. While initial efforts seemed to be limited to the northern Illinois market, suppliers are beginning to gain ground in the downstate areas. However, in Staff's view, customers need more suppliers to enter the market. A list of Staff's recommendations related to competitive issues can be found on page 45.

The basic issue addressed by the **Utility Service Obligations** section is whether or not present service obligations should remain the same after 2006. Reporting on the consensus of the Utility Service Obligations Working Group, this section of Staff's report concurs that the obligation to serve small-use customers should not change. Staff also agrees with the group's conclusion that obligations should remain unchanged with respect to large-use customers who are taking utility service that has not been declared "competitive." Disagreement within the working group arose over how, if at all, the PUA should be modified with respect to the declaration of "competitive" services. Disagreement also arose over how, if at all, service obligations should change with respect to customers subject to competitive service declarations. Staff's recommendations related to service obligations can be found on page 49.

The **Energy Assistance** section focuses on two major issues: how energy assistance programs should be provided for low-income customers who cannot afford to pay; and whether current State funding for low-income assistance programs is adequate. The Energy Assistance Working Group and Staff concur that the limit on eligibility for low-income assistance programs should remain the same. The group and Staff also concur that a new type of energy assistance plan that would base energy charges on a percentage of income should be more fully explored by policymakers, including the Illinois Commerce Commission. With respect to energy efficiency education programs, the group concluded that a pilot program might provide the evidence necessary to determine if such programs would help LIHEAP eligible consumers reduce energy costs. The group also determined that the perennial cycle of spring/summer disconnections for non-payment and fall/winter reconnections when LIHEAP funds become available is in the best interest of neither utilities nor consumers. However, the group did not reach any consensus on a proposal to amend current practices. If the Commission determines that amendments are needed to the current disconnection and reconnection rules, Staff recommends that further workshops be held. While no consensus was reached on whether municipal utilities and electric cooperatives should be required to participate in the State Supplemental Low-Income Energy Assistance Program, Staff notes that if the program's funding mechanism is permitted to expire in 2007 (as currently scheduled in the law), even voluntary participation will cease to be an option. However, Staff considers the renewal of the program to be an issue appropriately left to the General Assembly. Finally, although the group discussed potential changes to Part 280 (which establishes procedures pertaining to eligibility for service, deposits, payment practices, discontinuance of service, and complaints), neither the group nor Staff recommends any code part changes at this time. A list of Staff's recommendations pertaining to Energy Assistance can be found on page 55.

The **Implementation** section describes the activities of the Implementation Working Group, which was composed of the Office of General Counsel and the conveners of the five substantive working groups--Procurement, Rates, Competitive Issues, Utility Service Obligations, and Energy Assistance. The Implementation Working Group examined the other groups' reports to determine the ways in which consensus items

and significant non-consensus items discussed in those reports could be implemented. Toward that end, each of the substantive working groups prepared an implementation report summarizing how those items could be established in Illinois; in most cases, the implementation reports focused on the questions raised in Staff's White Paper. The Office of General Counsel then reviewed the implementation reports and provided its comments on the groups' suggested implementation methods. The Implementation Working Group Report is being provided to the Commission under separate cover.

Procurement

I. Introduction

The charge of the Post 2006 Procurement Working Group ("PWG") was to explore various procurement scenarios that could be implemented by January 2007 by Illinois electric utilities. Discussions focused on 12 scenarios, ranging from abandoning restructuring altogether to making use of auctions.

With the understanding that no single procurement strategy would eliminate all of the issues or concerns of all the parties, the PWG strove to identify the positive and negative characteristics of various procurement strategies. In the end, the group chose not to recommend a specific procurement strategy, but did develop a list of 18 desirable characteristics that the participants agreed should be a part of any procurement method adopted by the State. The entire list of consensus characteristics of the ideal procurement method is as follows:

1. It should be highly transparent.
2. It should allow for a competitive procurement approach.
3. It should provide for the opportunity for full cost recovery to the utilities if they follow the Commission approved procurement approach.
4. It should result in market-based rates for customers.
5. It should include a mechanism for translating the result of the process into retail rates.
6. It should facilitate and encourage supplier participation of all types in the wholesale market.
7. It should facilitate stable rates and mitigate rate volatility for applicable customers for relevant time periods.
8. It should allow for and accommodate RPS, DSM, low-income assistance programs, etc.
9. It should require an initial regulatory review to approve and an ongoing regulatory review to oversee and improve the procurement process.
10. It should be capable of implementation prior to January 1, 2007.
11. It should provide specific guidance on crucial issues such as procurement methodology, rate design and allocation of risks and provide flexibility to respond to market conditions.
12. It should provide an agreed upon procurement methodology, which if followed, minimizes the need for after the fact prudence review.
13. It should include reasonable features or contractual safeguards to manage counterparty credit risk.

14. It should reflect lessons learned from States that have restructured and the current state of competition in the retail and wholesale markets in Illinois.

15. Stakeholders should have the opportunity to review and comment on the procurement process and proposed actions.

16. It should clearly assign accountability and risks.

17. It should provide for prompt regulatory review and approval.

18. The stated public policy goals of insuring resource adequacy should be considered in the procurement process or elsewhere.

Since some of the 18 characteristics are closely related, it is convenient to discuss them within groups. Thus, for purposes of the discussion, below, Staff has grouped the 18 characteristics into just five basic categories. From Staff's perspective, these categories comprise the five overarching goals of the post 2006 procurement process: (a) mitigation of market structure problems, (b) provision of regulatory certainty for suppliers and utilities, (c) provision of market based prices and rate stability, (d) provision of a straightforward mechanism to convert supply acquisition costs into retail rates using traditional rate design, and (e) provision of a working procurement option by January 2007. Additionally, it is important to note that characteristics related to consumer interests are embedded within each of these five overarching goals.

The relationship between each of the PWG's 18 characteristics, the five overall policy goals, and consumer protections is shown in the following table:

Desirable Characteristics of an Ideal Procurement Method	Overarching Policy Goals				
	(a)	(b)	(c)	(d)	(e)
	Mitigation of Market Structure Problems	Provision of Regulatory Certainty	Provision of Market Based Rates and Rate Stability	Provision of a means to convert results into traditional rate design	Provision of a working option by January 2007
1*	X				
2*	X				
3		X			
4			X		
5				X	
6	X				
7*			X		
8				X	
9*		X			
10					X
11*		X		X	
12		X			
13		X			
14*		X			X
15*		X			
16		X			
17*		X			
18		X			

* denotes a characteristic that also addresses consumer interests

II. The Procurement Challenge

Illinois' post 2006 electric procurement structure can be designed to address challenges for the provision of bundled electricity service from its largest electric utilities. Foremost among them is the question of how those Illinois utilities that no longer directly own generation assets will acquire electricity to serve bundled load. The Illinois utilities in this category include the two largest in the state, Ameren and Commonwealth Edison ("ComEd"), which together served 97 percent of the bundle electric service in the state in 2003.[4] While utilities that remain vertically integrated (with their generation assets), such as MidAmerican Energy Company, can continue to procure electricity as they have traditionally done, Ameren and ComEd will have to turn to the wholesale marketplace.

The wholesale marketplace, from which ComEd and Ameren will be buying their electricity, is heavily concentrated by a few large generation companies. This is not

[4] Ameren is a holding company whose subsidiaries include the electric utilities AmerenCIPS, AmerenUE, AmerenCILCO, and AmerenIP. For ease of reference, these utility operating companies are referred to simply as "Ameren."

dissimilar from the market structures seen in many restructuring jurisdictions where the first step in restructuring has been to move generation out of the utility and into utility affiliate companies. ComEd has taken the further step by selling its fossil plants to a separate entity – Edison Mission Energy. Some of those large generation companies are the utilities' own affiliates, which are not directly subject to rate regulation by the Illinois Commerce Commission. Where concentration levels are high (particularly where one or two firms control a significant portion of production capacity), firms have the ability to exercise market power. While high levels of concentration do not mean that a firm will exercise market power necessarily, strong oversight and monitoring are required to ensure that such markets function properly and competitively.

Market concentration can be measured with the Herfindahl-Hirschman Index ("HHI").[5] Markets with HHIs in excess of 1800 are considered "highly concentrated." By way of comparison, the combined AmerenCIPS and AmerenUE service territory has a seasonal HHI of about twice the threshold for a "highly concentrated" market. Ameren's generation affiliate owns a significant proportion of the generation capacity that can economically reach two of Ameren utilities' service territories, and one independent generation company owns a significant proportion of the capacity that can reach another Ameren utility service territory. In the ComEd service territory, an affiliated generator owns a significant proportion of the capacity and the HHI ranges from just below to nearly double the "highly concentrated" threshold. Concerns arise primarily in a procurement approach where the utilities buy their power through bilateral or private negotiations with suppliers. This is so because, first, these suppliers have no obligation to sell to Illinois utilities and the utilities could be forced to negotiate with generators who can refuse to sell to them unless they buy at the supplier's preferred price. Second, while retail competition can act as a check on over-priced utility supply by offering customers more favorably-priced supply, for the residential market there has been no activity at the retail level. Finally, while the ICC must ultimately approve the rates charged to customers and both PJM/MISO and FERC oversee and monitor the competitiveness of wholesale activity, Staff does not believe a procurement model where the utility is negotiating, privately, for its supply is likely to result in the competitive process that will afford the best rates for customers. An auction process, in the very least, assures full transparency to all stakeholders.

There are several factors that help to counteract the problems described above. First, as a check against utilities favoring their affiliates in the provision of energy for

[5] The HHI is a commonly accepted measure of market concentration. The U.S. Department of Justice and the FERC, for example, use the HHI for evaluating mergers. A market with an HHI less than 1,000 is considered to be competitive, one with an HHI between 1,000 and 1,800 is considered to be moderately concentrated, and one with an HHI of 1,800 or greater is considered to be highly concentrated. To compute the HHI, one sums the squares of the sellers' market shares. The HHI can range from a minimum of close to 0 to a maximum of 10,000. An HHI approaching zero would indicate near-perfect competition, with many thousands of sellers with negligible market shares. An HHI of 10,000 indicates the existence of a single firm with 100% market share.

bundled customers, at least some customers may be able to find better prices from alternative retail suppliers. For those customers that cannot find better prices from alternative suppliers, the Commission maintains the authority to set just and reasonable rates under Section 9-201 and related sections of the PUA, and to conduct prudence reviews of wholesale purchases made by electric utilities that have tariffs creating fuel adjustment and purchased power adjustment mechanisms, pursuant to Section 9-220 of the PUA. Finally, the Commission has the authority to cap power and energy charges within bundled rates at 110% of the market value of power and energy, as outlined in Section 16-111(i) of the PUA. While such checks may help, they do not ensure that the goals of the PUA will be met. While no procurement method can be considered a panacea, Staff believes that some methods will mitigate the problems better than other methods.

In Staff's view, for procuring supply for large electric utilities that own little to no generation capacity (having spun off most or all of their generation assets), a vertical tranche auction (as explained in the subsections, below) would best mitigate the affiliate and market power concerns described above. This model, identified as scenario #1 by the PWG, can be structured to possess the 18 desirable characteristics identified by the group. Furthermore, for utilities with generation affiliates, the vertical tranche auction model apparently would satisfy the Federal Energy Regulatory Commission's ("FERC's") "Edgar standard" regarding arms-length transactions. The Edgar standard requires that a utility prove that any deal it makes with its affiliate was entered into through a procurement process that was transparent, nondiscriminatory, and clearly defined, contained standardized evaluation criteria, and was administered by an independent third-party. Indeed, of the procurement scenarios explored in the workshops, the vertical tranche auction most directly addresses concerns about utilities buying from their affiliates.

On the other hand, the vertical tranche auction model is not necessarily appropriate for all Illinois utilities. First, for Illinois utilities that remain vertically integrated (with their own generation), there is no critical need to deal with potential affiliate abuse or concentration in the wholesale power market. More traditional regulation of the electric costs can still be employed. Second, for very small utilities, particularly those with neither generation assets nor generation affiliates, a vertical tranche auction may not be a cost-effective means of acquiring electricity. For one thing, a small potential load may not attract a competitive array of bidders. In such cases, the Commission may be able to effectively ensure arm's length transactions at acceptable prices, without the need to implement an elaborate auction. It may be more appropriate to allow such small utilities to use formal requests for proposals ("RFPs") or even bilateral negotiations to attract power suppliers. While the Commission is already familiar with such traditional power procurement methods, vertical tranche auctions would be novel to Illinois. Hence, most of the remainder of this Procurement section deals with the known and expected properties of vertical tranche auctions.

While a vertical tranche auction is Staff's preferred procurement method, at least for some utilities, several caveats apply. First, since a "vertical tranche" is actually a

slice of the utility's bundled load, bidders in a vertical tranche auction are required to follow the load of the utility. That is, each supplier contracts to provide a percentage of the utility's "full requirements." As discussed later in this section, several developments must occur in order for the underlying wholesale market to facilitate such contracts. Second, while the vertical tranche auction may be the best option given the current state of the wholesale market, and while litigated rate cases for power and energy tariffs and delivery service tariffs will determine the actual prices customers pay in rates, the costs of power and energy developed in the auction will be the key determinant of those rates. That auction price may reflect the higher costs of the less efficient generators bidding into the market. Consequently, if auction prices settle at these higher levels, the current unregulated owners of the utilities' lower cost legacy generation assets can expect to realize profits that are greater than would be achieved under the pre-transition period structure. If conditions improve for generating highly competitive results from the vertical tranche auction, the Commission and utilities will need to explore ways to commit to a consistent process over time for the benefit of consumers.

These issues will be discussed more fully in the ensuing subsections. Before that, however, Staff should more fully explain the features of a vertical tranche auction.

III. Vertical Tranche Auctions Described

As outlined in the workshop documents:

> Scenario 1 envisions a load serving entity ("LSE") "vertically" dividing the load obligation being auctioned into "tranches," [a French word meaning "slices,"] each of which has the same load shape as the total load being auctioned. Prospective suppliers, which may include affiliates, offer full requirements products to serve one or more tranches, with the winning suppliers being selected via an auction. This process could be used for total load or for the load of one or more classes.

One example of a vertical tranche auction, discussed at length by the PWG, was the simultaneous descending clock auction approved by the New Jersey Board of Public Utilities and used by four New Jersey utilities. Assuming they meet sufficient credit standards, bidders in the New Jersey auction can range from purely financial firms to independent generation owners. Actually, separate auctions are held for each of two different classes of customers: (1) residential and small commercial and (2) large commercial and industrial. The pricing structure is dramatically different for those two auctions; the small customer auction results in a single price for all energy demanded, while the large customer auction determines only a capacity charge (after which the energy charge is determined in PJM's hourly spot market)[6].

[6] PJM is the name of an "independent system operator." It originally spanned Pennsylvania, New Jersey, and Maryland, but now encompasses additional service territories, including parts of Illinois. PJM serves several functions, including the coordination of transmission resources and the dispatch of generation, based on an hourly spot market.

For the small customer group load, contracts of both one and three year terms are auctioned in New Jersey; presumably, using three-year contracts serves to provide greater rate stability to the small customers. For each utility, each service type, and each type of contract (one or three year), the auction produces a uniform-price for all tranches. That is, all suppliers are paid the same rate for a given "product." This process is repeated each year, after which the auction prices are translated into individual retail rates for various bundled customer classes, based on their load characteristics. The translation formulas are subject to modification and approval by the New Jersey Board of Public Utilities.

There are of course many ways to structure a vertical tranche auction, other than the New Jersey model. There could be more or less than simply one and three-year contract terms. There could be more or less than two aggregate load classes. There are many details to consider in the rules of the auction process. Such details are beyond the scope of this report, but would need to be addressed in formal proceedings.

IV. Desirable Properties of Vertical Tranche Auctions

In Staff's view, vertical tranche auctions provide a viable means of achieving the five overarching policy goals for a preferred procurement methodology:

- Mitigation of market structure problems;
- Provision of regulatory certainty;
- Provision of market based prices and rate stability;
- Provision of a straightforward mechanism to convert a wide variety of supply acquisition costs into retail rates using traditional rate design; and
- Provision of a working option by January 2007.

A. Mitigation of Market Structure Problems

A primary concern to policymakers should be how the auction, relative to the other procurement methodologies, alleviates the underlying wholesale market problems in Illinois. A properly configured vertical tranche auction, backed by a relatively liquid wholesale market, should result in as competitive an outcome as is possible given the underlying concentration of generation assets in Illinois, and the dominance of affiliate interests in these markets.

In terms of dealing with market power and affiliate abuse concerns, the transparency of the vertical tranche auction is its central strength. This transparency is provided by the uniformity of the auctioned vertical tranche full requirement product as well as the bidding mechanism of the auction. Relative to requests for proposal (which are bilateral processes traditionally used in the

Midwest for the procurement of electricity), an auction for a uniform product increases the comparability of offers. The comparability of the offers, in turn, increases competition among suppliers and provides transparency to the process. Suppliers are, in the end, evaluated solely on the price upon which they can supply a pre-defined product. Since all potential suppliers are ultimately judged on the same observable criterion, this minimizes the potential for utilities to provide favorable treatment to their affiliates, and reduces the burden of regulatory oversight. The bidding mechanism also provides a means for bidders to have their bids considered objectively, fairly, and simultaneously, further adding to the transparency to the process.

Furthermore, using a descending-clock format for the auction (as in New Jersey) results in a single market-clearing price for all tranches. In a sense, this too may lead to transparency, since that price sends a clear price signal to suppliers regarding the profitability of future supply projects.

Another aspect of the vertical tranche auction that can enhance long-term competition is the ability to stagger the term structure of supply contracts, so that only a portion of the utility's load is up for auction in any given year. If, for example, load was supplied via three-year, overlapping contracts, one-third of the load will be up for auction each year. A supplier operating in the market would have an opportunity to secure a continuing place in the overlapping contracts awarded in the auction. The availability of long-term load commitments, via the overlapping contract opportunities, may help existing and potential generator owners secure financing for capacity additions.

In addition to the above characteristics, the vertical tranche auction could place caps on the number of tranches that any one supplier could directly serve. This has been done in New Jersey to prevent the dominance of any one potential supplier, particularly large affiliated generation companies. While such a cap would limit an individual firm's direct involvement in an auction, the cap would not prevent a large generation company from indirectly supplying electricity to other market participants (through the markets for standard wholesale energy products). Preventing a single large firm from dominating the auction reassures smaller suppliers that participating in the auction is not a waste of their time and resources. This increases the array of competitors that show up to bid.

B. Provision of Regulatory Certainty

Another concern raised during working group discussions centered on the regulatory certainty that a given procurement mechanism can provide the marketplace, particularly the utilities and their potential wholesale suppliers. In order to get the best and greatest number of offers in the auction, bidders must be confident that the results of an approved auction process will be accepted. As has been shown in other states, notably New Jersey, an auction mechanism can be designed to provide such certainty. Since the auction's structure and procedures would be vetted and approved by the Commission prior to the auction's actual

execution, acceptance of the auction's final results should be fairly routine. After the fact review would tend to be limited to fine tuning the process, rules, or products for the next year's auction. The downside of this certainty is that there tends to be no mechanism (other than, for example, a two-day New Jersey Board of Public Utilities review) to ensure against auction-driven prices that are unreasonably high; the hope is that if the auction is structured correctly, unreasonable prices are not possible, almost by definition.

As mentioned in the previous section, the transparency of the auction process also serves to reduce the risk of after the fact prudence review of individual contracts. The auction, rather than the utility, determines how much suppliers are paid and how much they supply toward meeting bundled load. This reduces the need to scrutinize utility decisions and potential favoritism toward affiliates. In addition, the use of a State-approved competitive bid process, such as a vertical tranche auction, addresses FERC's requirements for arm's length transactions between utilities and their wholesale affiliates.

C. Provision of Market Based Prices and Rate Stability

Market based prices to retail customers and rate stability for retail customers are two important goals for a procurement methodology. While separable and distinct, these two goals are best discussed together because, to some extent, there is a conflict between them. Since the incremental cost for energy changes by the hour, locking in prices via contracts for longer periods provides price stability for customers but would cause a separation between prices offered in the real time wholesale market and those paid by retail customers. The greater the rate stability offered to customers, the less the retail rates may reflect market based prices over time.

On the one hand, to the extent real-time wholesale prices are volatile, or simply on the rise, stability is clearly desirable from the consumer's perspective. On the other hand, to the extent that wholesale prices are decreasing over time, customers will be slow to benefit from those decreases if their retail rates are tied to long-term supply contracts. Furthermore, where wholesale prices change dramatically between contract lock-ins, customers may face considerable sticker shock when the bundled rate is eventually revised. Finally, separation between real-time wholesale market prices and the prices paid by retail consumers is sure to lead to inefficient levels of energy consumption (too much in the on-peak and too little in the off-peak hours). Similarly, without appropriate price signals, customers may not be able to make well-informed strategic decisions regarding long-term investments in energy-intensive equipment.

Clearly, it is up to policymakers to strike the appropriate balance between how quickly rates respond to wholesale market forces and how well they insulate customers from market volatility. However, Staff notes that the vertical tranche auction does not limit the Commission's options. A vertical tranche auction, repeated every year, will enable bundled rates to adapt to long-term trends in the

wholesale market, while still providing a large measure of rate stability within the year. As previously noted, meeting some portion of the load through longer-term contracts (e.g., three-year contracts) adds rate stability between years.

To address the differing needs of various customer classes, and perhaps to group the costs of switching risk with the customers that are more likely to engender such risk, more than one type of product could be developed. A utility could, for example, offer two basic products—a relatively stable product for small customers based on overlapping multi-year full requirements contracts with suppliers, and a shorter-term product for large customers (or for large customers whose power and energy service has been declared competitive). As previously noted, in New Jersey, the short-term product's energy charge is tied directly to the PJM hourly spot price, and only the capacity charge is fixed for one-year terms. Securing two different types of supply contracts enables the utility to provide a market-based but significantly stable price for small customers, and a market-based but clearly more volatile price for large customers. Staff provides further comments concerning an auction's implications for rate stability in the Rate section of this report.

D. Provision of a Straightforward Mechanism to Convert Supply Acquisition Costs into Retail Rates using Traditional Rate Design

A vertical tranche auction poses no special problems for retail ratemaking. For example, in New Jersey, which employs a simultaneous descending clock auction to procure supply for vertical tranches, the auction results in a fixed price for each supply product, which can be easily converted into electric rates for individual customer classes. Furthermore, while Staff makes no recommendation regarding whether the Commission should require fuel diversity, order minimum renewable portfolio standards, or place other such constraints on bidding suppliers, the use of a vertical tranche auction would easily accommodate such policies. For instance, if specific levels of "green" power become mandated through new Federal or State legislation, bidders in the vertical tranche auction could be required to certify that their full requirements products meet those standards. More generally, the objectives of fuel diversity, demand response requirements, or programs designed to help low-income consumers pay their utility bills can be pursued within the context of an auction process.

E. Provision of a Working Option by January 2007

It is likely that a vertical tranche auction, as described above, could be in place before January 2007.[7] Notably, New Jersey has been successful in implementing a vertical tranche auction annually for the last three years. The results of the auction have been found to be reasonably competitive and acceptable by New Jersey's Board of Public Utilities every year since the auction's inception. Other states are

[7] Staff has been constructing suitable timelines for the development, approval, and implementation of such a procurement auction. After soliciting input from interested parties, Staff will distribute a sample schedule for the Commission's review.

using the New Jersey auction as a blueprint for their own plans to obtain supply for bundled service.

Staff is concerned that the Commission may not presently have the authority to mandate an auction as a procurement methodology. Absent a clear legislative expression of the Commission's authority to mandate such a process, the establishment and continuation of the auction process over time may depend on a utility's voluntary participation along with the agreement with intervening groups. This may not prove to be a serious concern if FERC maintains its current requirements that transactions between utilities and their affiliates must be reached via a non-discriminatory and competitive process, such as an auction. As long as the FERC remains firm on that policy, the utilities will have an interest in maintaining the auction as a means of contracting with their affiliates.

V. Wholesale Market Requirements for a Successful Vertical Tranche Auction.

There are several prerequisites that the wholesale electric market must satisfy before policymakers can expect to obtain a relatively competitive outcome from any of the procurement methods discussed by the PWG (including the vertical tranche auction method).

First and foremost among these requirements is a wholesale market for electricity overseen by an independent system operator ("ISO") such as PJM or the much younger Midwest ISO ("MISO"). If all goes according to their plans, both MISO and PJM will be in a position to provide market-based least cost regional dispatch of generation units in each of their real time markets within Illinois, by the time a vertical tranche auction can be in place within Illinois. Both ISOs will determine hourly locational market prices ("LMPs"). Both ISOs will allocate and permit trading of financial transmission rights ("FTRs") as a means of hedging congestion costs on their systems. In fact, PJM currently provides these market mechanisms in the ComEd service territory. MISO is scheduled to provide similar service to downstate Illinois utilities by March 2005.

Of particular importance is an ISO structure that facilitates a regional market for energy, as well as for capacity and FERC-defined ancillary services. Under traditional market rules and definitions, suppliers of firm capacity and ancillary services are largely confined to the resources within a specific utility's service territory. Such localized markets in Illinois tend to be heavily concentrated and dominated by the unregulated generation affiliates of the electric utilities. This situation, if it exists at the time of the auction, would call into question the competitiveness of the capacity and ancillary service markets that would be used to serve firm retail load commitments within these utility territories. Since the providers of full requirements energy will, by definition, need to acquire sufficient capacity and ancillary services to meet their firm commitments to supply retail load, the overall competitiveness of the capacity and ancillary services market will directly impact the number of players that can effectively participate in the auction, and how

competitive these participants can be with the incumbent generation owners. In order for the auction to work as well as intended, and as well as it has in New Jersey, regional markets capable of supplying capacity and ancillary services to specific load centers in Illinois must be in place before the auctions start. This means that the ISO market design at the time of the auction must support the ability of potential suppliers to designate network resources outside the service territory in which they are serving load and it must support a way for ancillary services to be procured from reasonably competitive regional markets. At present, only PJM offers these services. It is unclear if MISO will provide similar services by the end of 2006.

Another requirement will be a regional market of sufficient size to mitigate the heavy market concentration that exists among generation owners in specific Illinois utility service territories. The transparency and liquidity of the markets made possible via regional ISOs will serve to provide, relative to the more traditional markets found in the Midwest, a far greater number of resources that can be drawn upon to efficiently serve and support load. Providing a market where geographically diverse generators must compete on a daily basis to provide power to the grid reduces the relative importance of what might otherwise be local monopolies. The greater the footprint of the regional dispatch market, and the fewer the barriers to trade between utility control areas, the greater the level of competition in the energy market.

To ensure the greatest possible pool of potential wholesale supply that can be used to provide full requirements energy to Illinois utilities, the institutional “seams” between MISO’s market and PJM’s market must be minimized or eliminated. This will require the elimination of artificial barriers to the movement of power across the two ISOs. Without the elimination of such barriers, the competitiveness of the regional energy market will suffer. The sooner MISO is operational, the sooner PJM and MISO can iron out such seams issues. In this regard, the Commission should do everything it can to ensure that MISO adopts a market design for both ancillary services and capacity that is compatible with the PJM system. In the event MISO has yet to implement such a compatible market design before the end of the transition period, policymakers may need to consider alternatives or modifications to the vertical tranche auction as a procurement method for the affected utilities, until these shortcomings are resolved. In the long run, it is unacceptable for “seams” to persist between the MISO and PJM markets, if Illinois hopes to fully capture the benefits of trade in the wholesale power market.

Another critical requirement of the wholesale market is that the winners of the auction must have non-discriminatory access to the FTRs that the ISO make available in their annual allocations to load serving entities (“LSE”). To ensure that all potential suppliers, including alternative forms of energy such as wind, solar and demand response, in every auction have equal access to FTRs and transmission resources, it will be necessary for auction winners to be considered LSEs under ISO tariffs. The LSE designation guarantees suppliers a chance to obtain FTRs during an ISO’s annual FTR allocation period; it also gives suppliers the right to reserve

transmission and designate network resources. Absent the LSE designation, auction winners would have to bargain with the incumbent utility or with their competitors in order to obtain FTRs, network resource designations, and transmission services. This could place some suppliers at a significant competitive disadvantage. It could also raise concerns regarding the potential of utilities to favor their affiliates relative to other suppliers.

If the state desires to create an opportunity to develop alternative resources, the auction process must be consistent with ISO rules. If the objective is to create a "level playing field" in the auction process, then the state could require bids to reflect the full societal costs of all energy sources, including both traditional and alternative sources. This would enable an alternative energy source with low environmental costs to compete against traditional sources.

From the auction design side, there are steps that should be taken to ensure that the auction takes the greatest advantage of the markets and services that the ISO will have available. For example, in order to maximize the efficiency of suppliers' hedging opportunities, the auction should be appropriately synchronized with the ISO's allocation of FTRs so that auction winners have adequate time to nominate FTR requests in each ISO's annual FTR allocation. Improving the efficacy of suppliers' hedging opportunities should, in turn, enable utilities to obtain fixed price full requirements products at the least cost. Absent such a line up, any FTRs acquired in secondary markets between allocation periods may tend to be less efficient congestion hedges than FTRs that would have been granted through a direct allocation from the ISO. That is, FTRs acquired in the secondary market will not constitute a suitable hedge unless their new owner's generation resources and customer loads are located in the same areas on the electric grid as the original owner of the FTRs (which seems an unlikely coincidence).

VI. Summary of Staff Recommendations

Staff's recommendations concerning post 2006 procurement are as follows:

- The Commission should remain receptive to more than just one procurement plan.

- Large Illinois utilities that do not own significant generation resources should be encouraged to procure their electricity via a vertical tranche auction, as exemplified in Scenario 1 of the Procurement Workshop Report. This assumes that transmission systems and wholesale markets can appropriately accommodate such auctions.

- The Commerce Commission should clarify its authority to implement the use of any given procurement methodology, in general, and a vertical tranche auction, in particular.

- Illinois policymakers should continue to work to ensure that PJM and MISO's LMP and FTR markets are fully functional and completely resource non-discriminatory before the end of 2006.

- Illinois policymakers should continue to work to ensure that market "seams" between MISO and PJM are eliminated.

- Illinois policymakers should work to ensure that there exist regional markets for ancillary services and capacity within and between MISO and PJM.

- Illinois policymakers should work to ensure that the winners of a vertical tranche supply auction are given LSE status for purposes of PJM and MISO tariffs.

- Illinois policymakers should work to ensure that auction winners can receive annual FTR allocations from MISO and PJM.

Rates

I. Introduction

This section of Staff's report considers rates issues to be addressed in preparing for the post 2006 era. The report takes note of the Rates Working Group's (RWG) agreements on a host of issues. It then focuses on issues that were not resolved by the consensus process. The report presents Staff's perspectives on these issues and discusses how they may be resolved in the regulatory process. The report does not provide a detailed blueprint for how rates should be developed for each electric utility in the post 2006 era. Rather, it identifies certain key principles that will guide Staff's recommendations in upcoming rates proceedings.

The RWG, like other working groups, concentrated on ratemaking issues related to the securing of power and energy for bundled utility customers. Consequently, most of its discussions centered on the pricing of power and energy, and related issues. A number of contentious issues were discussed which either eluded consensus or produced limited agreements. These issues will have to be revisited and decided within Commission proceedings where stakeholders have the opportunity to argue their respective positions.

The RWG reached a number of decisions that are important and useful in setting the regulatory landscape for the post 2006 era. While the discussion focused on issues related to rates for electric power and energy, the RWG agreements have important ramifications for the delivery component of electric service, not just for unbundled customers, but for bundled customers as well.

The remainder of this section is organized as follows. First, issues pertaining to the delivery component of post 2006 rates are examined. Second, there is a discussion of the power and energy component of rates. Third, the issue of uniformity is discussed. Fourth, renewable power and other environmental issues are addressed. Fifth, there is a discussion of the regulatory process necessary to address outstanding rates issues for the post 2006 era. Finally, Staff's recommendations on ratemaking issues are summarized.

II. The Delivery Component

In the post 2006 era, utilities will continue to serve two sets of customers. One set consists of bundled customers who will rely on the utility for their full electricity needs, purchasing their power from the utility that will deliver it to their home or business. The second set consists of unbundled customers who will purchase electricity from alternative suppliers and delivery services from the utility. Thus, while bundled and unbundled customers may purchase their electricity from different sources, all electricity is delivered to them over the incumbent utility's network.

A. Customer Billing

A key part of the Commission's Post 2006 Initiative concerned how to foster competition in the power market. The RWG, along with other working groups, sought to reach agreements that would achieve this objective. One agreement the RWG reached would facilitate competition and also guide the setting of delivery rates for both bundled and unbundled customers. The agreement is summarized in the Executive Summary of the Post 2006 Initiative RWG report as follows:

> The RWG reached consensus that, when filing bundled service tariffs, utilities should separately determine the cost of the commodity component and provide unbundled price information to customers. In addition, the prices related to services that can be provided by a competitive Metering Service Provider should be unbundled even in tariffs where the services remain bundled. A single proceeding should be used by each utility to determine the unbundled delivery services rate and the distribution components of the bundled rates. Utilities should endeavor to synchronize the delivery charges in their unbundled rates with the delivery price components of their bundled rates. In addition, utilities should move towards synchronizing the bundled and unbundled customer classes.

Staff recommends that the Commission adopt the RWG's agreement on this issue. If customer bills clearly present the cost of electricity apart from delivery service charges, then ratepayers can more easily compare the cost of bundled power with bids by alternative suppliers. For that comparison to be meaningful, the charge for delivery must be the same whether the utility or an alternative supplier provides the generated power. Divergence between the two would make it difficult to compare the price of power and energy offered by the utility and the alternative suppliers. Shopping for electricity would become far more complicated and the development of a competitive power market would be impeded.

Staff does not consider the agreement to separate out the cost of metering on all bills as crucial at this juncture. Competition has yet to evolve for metering services and there is no meaningful alternative at this time to service from the utility. However, that could change in the future as technology advances and prices decline. In the meantime, Staff sees no harm in separating out the cost of metering on all bills.

B. Developing a Single Set of Delivery Rates

Staff recommends that the Commission follow the counsel of the RWG and conduct a single proceeding to determine a delivery rate common to all bundled service and delivery service customers, within each customer class, for each electric utility in the post 2006 era. This would streamline the regulatory process and avoid the cost and confusion that would be created by separate and, possibly, concurrent proceedings for bundled service and delivery service.

Staff notes that the Commission will face a significant challenge in developing a single set of delivery rates for bundled and unbundled customers. Significant differences exist between the current rate structures for bundled and unbundled service. As customers are reconfigured and consolidated into a single set of classes, some ratepayers could encounter significant changes in their electricity bills. Thus, temporary mechanisms may be desirable to mitigate significant rate increases individual customers could experience during the transition to a single set of delivery rates.

Such temporary rate mechanisms must recognize that most customers currently receive bundled service from the utility. Those rates were based on power coming from plants owned by the utility itself. However, the electric power industry has changed considerably since those rates were set. With the inception of the Restructuring Law, most utilities transferred their generation facilities, largely to affiliated companies. In part because of these structural changes, power and energy costs will change and so will electric rates for end-use customers. Bundled customers may encounter significant modifications in how their bills are calculated, with some bundled customers benefiting and others suffering adverse impacts. While the primary goal should be to set rates based on the cost of service, Staff recommends that the Commission consider the resulting rate impacts when setting post 2006 rates.

The Commission has a head start in developing a common set of delivery rates for bundled service and delivery service customers, having conducted two sets of delivery services proceedings for all electric utilities in Illinois since 1997. These proceedings provided the Commission direct experience in setting delivery rates, and further deepened and refined the Commission's knowledge and thinking on ratemaking issues. Ongoing discussions of cost platforms, cost allocation and rate design continue to build a strong foundation for the post 2006 rate setting process.

The process of developing a single set of delivery rates must take into account the power procurement method adopted for bundled customers. One reason is that the procurement methods being considered may have implications on the grouping of customers into rate classes. For example, the New Jersey-style auction, discussed more fully by the Procurement Working Group, would implement separate auctions for small and large customers, featuring fixed prices for small customers and hourly prices for large customers. This approach may require grouping customers according to which auction applies, resulting in rate classes that differ from both existing bundled and delivery service classes. The selection of an alternative procurement method may also have ramifications for grouping customers into rate classes.

Future rate proceedings will involve the types of issues that were examined in the Commission's recent delivery services proceedings, as well as its more traditional bundled service rate cases. These issues would include: how cost and non-cost factors should be considered in the rate setting process, which costing methodology should be used, and how costing methods should be applied to develop rates. If

past Commission proceedings are indicative, the development of delivery rates for the post 2006 era will be contentious.

In addressing post 2006 delivery rates, Staff recommends that the Commission continue to adopt the ratemaking approach that it developed and refined in previous delivery service proceedings. For example, the Commission should ensure that the overall levels of joint and common costs are developed in a similar manner as in previous delivery service cases. The Commission should also reaffirm its support for an embedded approach to allocate costs and design rates. In Staff's estimation, the arguments favoring an embedded cost approach in previous cases continue to provide a reasonable and straightforward basis for designing rates in the post 2006 era.

III. The Power and Energy Component

Developing rates for the power and energy procured by utilities will be a key challenge for the Commission in the post 2006 era. The Commission will have to contend with a transformed market for power in Illinois. Currently, bundled customers purchase electricity under frozen rates, which were established before 1997, in a traditional cost of service environment where utilities supplied ratepayers with power from their own generation. Since those rates were developed, some utilities, including the two largest, ComEd and Ameren, have divested all of their generation to affiliates or non-affiliated entities. Those utilities must purchase their power in a wholesale market that, from Staff's perspective, has not yet proven to be workably competitive. The Commission will have to adapt its ratemaking practices to fit this fundamental change in how power is acquired for Illinois ratepayers.

A. RWG Agreements

The primary focus for the RWG was electricity pricing for bundled customers in the post 2006 era. As the RWG found, the development of retail electric prices largely depends on how electricity will be procured in the post 2006 era. For example, if electricity is purchased at a fixed price through an auction process, then it may be reasonable to set fixed electric rates for consumers. Offering consumers fixed prices would be more problematic if electricity were to be procured on the spot market where prices can change from one hour to the next. Thus, the RWG had to examine each of the methods for procuring electricity under consideration for the post 2006 era. The fact that a total of twelve different procurement methods were being considered created significant complexity for the RWG's deliberations.

Nevertheless, the RWG did reach a number of useful agreements on a host of electric ratemaking issues. Those agreements pertained to price stability, real time rates, allocation of utility costs between bundled and unbundled customers, charges to customers who leave or return to bundled service, and rates that serve to control loads or promote efficiency. The agreements were general in nature due to disagreements among stakeholders with differing interests and objectives that prevented more specific agreements. They are as follows:

- The stable pricing agreement stated that utilities should hedge against variations in electric prices so that they can offer residential and small commercial customers stable prices that are fixed for at least a month at a time. The RWG could not reach similar agreement concerning hedging electric prices or offering price stability to larger customers.

- With regard to real time pricing, it was agreed that hourly prices should continue to be offered to all non-residential customers, but no agreement was reached for residential customers.

- The consensus concerning cost allocation between bundled and unbundled customers was that only bundled customers should pay all costs related to commodity acquisition. None of those costs should be allocated to unbundled customers who purchase from an alternative supplier. Conversely, where customer migration imposes a cost, the consensus was that returning customers may be expected to pay the incremental costs associated with their return to utility commodity service.

- The discussion of load control and curtailment rates produced agreements that lent support to the premise that "properly designed interruptible, curtailable, and direct load control programs can promote system efficiency". The RWG also recognized that the structure of rate blocks could have a material effect on optimizing system efficiency.

A few general conclusions can be gleaned from these agreements. First, ratepayers in general prefer prices to be stable rather than fluctuating. Representatives of all consumer groups expressed a preference for stable prices. However, utilities were reluctant to accommodate larger customers with respect to stable prices.

Second, RWG participants accord a significant role to the cost of service in the design of power and energy prices. The agreement that only bundled customers bear commodity acquisition costs reflects an endorsement of the cost causation principle that ratepayers only pay those costs they cause the utility to incur.

As previously noted, the RWG had to consider a dozen different procurement strategies in its deliberations. Staff is not similarly hampered in discussing rates issues for this report. Staff endorses a single preferred approach for utilities that have divested generation. That approach is an auction in which sellers compete to sell uniform "vertical tranches" of the utility's total load. This decision should narrow the focus of the discussion of ratemaking issues for electricity. Furthermore, for utilities such as MidAmerican, which remain vertically integrated and continue to own generation, it would be reasonable to assume that they will be the source of power for their own bundled customers with rates developed under a traditional cost

of service regimen. This narrowing of procurement choices for Illinois utilities will allow a more focused discussion of electric rates issues.

B. The Auction Process

As is discussed in the Procurement Section, key elements of a vertical tranche auction are that winning bidders commit to providing a fixed proportion of the utilities' load at a uniform price. The exact nature of the product or products being bid upon would be subject to Commission approval. This is the case in New Jersey, which conducts a vertical tranche auction, where utility load is divided into two parts, for which a separate but simultaneous auction is held annually. For residential and smaller commercial customers, the auction produces a single fixed price per kilowatthour for each of the utilities and each of two different contract terms (one-year and three-year). For larger customers, the auction produces a single capacity charge, but uses hourly spot prices for all energy sold during the year.

While the utility may pay a single price for electricity procured through an auction, that does not necessarily mean that all ratepayers will see that same price on their monthly bills. In New Jersey, power prices are not uniform for all ratepayers. Rather, the rates vary according to each group's expected contribution to overall electric costs. Prices for customer groups are determined by their respective load factors. Those customers with lower load factors are typically more costly to serve on a per-KWH basis because they have proportionally higher demands during peak summer months when electricity is more costly. Conversely, higher load factor customers consume a larger proportion of their electricity in non-summer months when costs are lower. Thus, the underlying costs would support a higher price per KWH for low load factor customers than high load factor customers.

There are a number of ratemaking issues for the Commission to consider with respect to the auction process. First is the issue of price stability. Retail rates have been frozen in Illinois for a number of years. A key issue will concern the degree to which prices change in the future. Second, while the auction may yield a single price for a utility, it cannot be assumed that all ratepayers will pay that same price. The prices paid by ratepayers may depend on their respective contributions to the overall auction price. The Commission will have to develop a set of principles for apportioning electric prices.

C. Price Stability

Adoption of a vertical tranche auction, similar to the one used in New Jersey, would be consistent with the agreements reached by the RWG with respect to price stability. Under the auction process, residential and small commercial customers may receive constant prices between auctions, which in New Jersey is one year. In addition, layering in longer-term supply contracts (such as three year products) also contributes to retail price stability. It should be noted that there could be a monthly true-up to reflect differences between expected and actual usage patterns by different rate classes. However, the amount trued-up is apt to be only a small

fraction of overall electric costs. On the other hand, in New Jersey, large customers are required to pay hourly spot energy prices, with the auction only setting the capacity charge. Hence, if that system is used in Illinois, any desire by large Illinois customers for price stability may not be satisfied.

The price stability offered by an auction process is consistent with the concerns voiced by the RWG on this issue. The RWG agreed that commodity prices for residential and small commercial customers should be fixed for a minimum of one month. In New Jersey, the utilities lock in per unit supply costs for terms of one year or longer, through the auction. These per unit supply costs facilitate the type of stability in retail rates that the RWG and Staff find appropriate. However, while retail rates can be pre-determined for an entire year at a time, this does not prevent the New Jersey Board of Public Utilities, nor would it prevent the Illinois Commerce Commission, from employing seasonal or other rate designs as deemed appropriate, to preserve or improve economic efficiency while reducing both the costs of suppliers as well as the ultimate prices determined through the auction.

For larger customers, the RWG could not reach consensus on a term for price stability. Staff believes that price stability is an important consideration for all ratepayers large and small. Price fluctuations create uncertainty for ratepayers, making it difficult to budget expenses and plan for the future. Stable (and reasonable) prices represent a significant benefit for consumers.

Given this concern, it is unclear to Staff why prices for larger customers should vary on an hourly basis. While suppliers may find hourly prices to be advantageous, the customers themselves may not. Staff recommends that the Commission consider requiring the utilities to provide large customers with a product that gives them greater price certainty. Furthermore, if an hourly price plan were to be adopted, Staff would recommend that the Commission consider limiting that plan to only the largest utility customers, perhaps in the 3 MW and above range because these are the customers likely to have the most competitive alternatives.

Staff is also concerned that rates under a New Jersey auction process can vary because of a monthly true-up to reflect differences between projected and actual usage by different customer classes. The amount of costs subject to the true-up is relatively small. The Commission should decide whether such a true-up is necessary and may find it preferable to let utilities absorb any surpluses or shortfalls, especially if the amount to be trued up is as minimal as suggested.

D. Ratemaking Principles

A key issue concerns the roles of both cost and non-cost factors in setting post 2006 electric prices. This issue was examined in depth by the RWG, which concluded that costs should be an important, but not the only, consideration in the design of rates. However, differences did emerge concerning the primacy that should be reserved for cost and the parties could not reach any further consensus concerning the relative roles for different factors.

In Staff's opinion, power and energy rates should reflect the cost of service to the extent possible. A cost-based approach serves two purposes. First, it is generally believed to promote efficiency and produce more economic decision-making by consumers. Second, a cost-based approach is equitable: fairness results from having ratepayers pay only those costs they cause the utility to incur. Furthermore, there is no workable alternative to a cost-based standard for ratemaking. Alternative approaches that promote social goals or encourage economic development draw the Commission into an arena for which the General Assembly is better suited.

That is not to say that the Commission should base rates solely on costs. Staff believes that customer impacts and ability to pay are legitimate concerns and should be considered. Nevertheless, a focus on non-cost factors has the potential to produce arbitrary results that are inefficient, uneconomic and, in the end, counter-productive. To avoid such a result, Staff recommends that the Commission continue its longstanding effort to base electric rates on costs.

If an auction results in a single year-round price for electric supply, Staff recommends that the price be divided into a higher summer and lower non-summer price and apportioned among classes on a cost basis to the extent possible. As is the case in New Jersey, customers with lower load factors (who use a higher proportion of electricity during peak periods) would pay a higher average price than customers with higher load factors (who have more balanced year-round demands).

The exact method for translating auction prices into retail prices for customer groups cannot be detailed in this report. It will require additional updated information from utilities about their customer classes. However, the overall concept of basing costs on customer load factors is a sound concept that aligns ratemaking for power and energy costs with cost of service principles. Thus, by reaffirming its longstanding commitment to cost-based rates, the Commission can signal its desire to employ customer load factors in apportioning costs.

Determining electric rates for large customers subject to hourly spot prices and an auction-determined capacity charge can be a straightforward process. For example, in New Jersey, the large commercial and industrial customers are equipped with real time meters; they pay the real-time spot price for energy, and the auction-determined capacity charge based on their historical contribution to summer coincident peak load.

E. Ratemaking for Vertically Integrated Utilities

Utilities that remain vertically integrated would be subject to traditional regulation, which in the past has yielded stable prices. Whether prices are to remain stable in the post 2006 era is a decision for the Commission to make in future rate cases for these companies. Furthermore, the specific design of those electric rates will be addressed within future rate cases. Nevertheless, Staff recommends that pricing

issues in a traditional ratemaking environment should also reflect costs to the extent possible. If those costs do not change on an hourly or monthly basis, that would obviate the need for rates that fluctuate daily or over the course of a year. Nevertheless, it would appear that costs for the utility itself would be higher during the summer, which would provide a foundation for seasonal and time-of-day rates.

IV. Uniformity

The interest the two largest utilities have expressed in an auction process indicates that the electricity market in the post 2006 era will move increasingly toward a more uniform, statewide marketplace, at least with respect to the procurement of electricity. In the auction process, suppliers will be able to bid for blocks of customer loads in more than one utility service area in the same auction. They will be able, for example, to switch their bids from ComEd to Ameren and back, depending on how the process unfolds.

The issue is whether the movement toward uniformity in procurement will extend to other utility matters. The activities of the RWG suggest that uniformity may be a worthwhile endeavor for rates as well. The RWG has conducted a single set of workshops on rates issues that cover all electric utilities in Illinois.

In Staff's view, more uniform ratemaking is a worthy regulatory objective. A uniform ratemaking approach would ensure that ratepayers across the state are treated more consistently and more equitably. It would also improve the understandability of tariffs, both for customers with facilities in more than one electric utility's service area and for regulators and other interested persons, by reducing the learning curve necessary to understand the tariff of each electric utility in Illinois. Therefore, reason and logic argue for continuing the efforts to develop a more uniform approach to ratemaking at both the generation and distribution levels by all Illinois utilities. That is an objective Staff will pursue through its participation in upcoming rate proceedings.

V. Renewable Energy, Conservation and Demand Response

The Commission Staff considers renewable energy, conservation and demand response to be closely related. These are alternative approaches to the traditional supply options that have been relied upon to meet customer demands. Furthermore, they are generally considered to have lower environmental impacts than current supply sources and are therefore advocated on this basis.

There were sharp debates and disagreements among RWG participants over renewable energy issues. . Participants fell into two camps: (1) those who wanted to set strong standards for future levels of renewable energy supplies and (2) those who wanted to maintain the status quo.

Renewable energy was advocated on three levels, first as a means to mitigate the adverse impact of electricity generation on the environment second, as a way to

further diversify energy supply in the State and thereby insulate ratepayers from problems associated with any individual source of supply and third, as a way to increase grid reliability due to the distributed nature of alternative energy resources and the positive impact on the grid. While some participants were supportive of the concept, others were opposed. The opposition centered on cost. If a focus on renewables led to higher prices, it was argued that ratepayers should not be saddled with the additional cost. The issue also arose over the possible need for legislative action to implement a renewable energy policy. Staff notes that the State of New York recently implemented a renewables policy without legislative action, although this action is not determinative of whether Illinois law currently permits this Commission to create a renewable energy policy.

The disagreements among stakeholders limited consensus to the following:

> The RWG reached consensus that the question of whether a renewable portfolio standard ("RPS") should be mandated by Illinois after the end of the Mandatory Transition Period is an important issue and that there are considerations that must be reflected in a workable RPS, if one is mandated, including:
>
> - Any RPS must be aligned with the post 2006 procurement process and facilitate the acquisition of cost-effective renewable energy.
> - Any RPS must be competitively neutral and consistent with the consensus on RPS issues reached by the Competitive Issues Working Group.
> - Any RPS must address cost recovery consistent with the consensus reached in the Rates Working Group.
> - Any RPS must consider the effect of the use of renewable resources on rates.

There was disagreement, however, on whether or not an RPS should be mandated by the State of Illinois, and on whether other alternatives for stimulating cost-effective renewable resource development (*e.g.*, green rates) should be adopted. The RWG did not reach consensus that any particular legislative amendments were required, and no specific amendments are proposed by the RWG. Similarly, the RWG did not reach consensus that any legislative change is required to accomplish any of the consensus recommendations or actions identified in this Report.

Staff recommends that the Commission adopt a policy consistent with the above consensus by the RWG. That policy may be pursued as previously discussed in the auction process, by considering alternative energy resources, including wind and solar generation, conservation and demand response methods as options to meet customer loads. Any RPS that is adopted should not conflict with procurement processes endorsed by the Commission, should be competitively neutral, should address cost recovery by utilities, and should be adopted only after considering its

effect on rates and other economic impacts on Illinois, including health costs, electric distribution investment and job creation.

Environmental objectives can also be pursued in the design of post 2006 electricity rates. Until now, utilities have had little or no incentives to promote renewables or conservation. If the Commission or policy makers decide that these are worthy goals for the state to adopt, then rate design provides a useful tool to use. Specifically, rates should send signals for consumers to consume energy at an efficient level. To that end, the Commission may wish to consider eliminating or limiting the use of declining block rates. In addition, interruptible and load control rates provide an alternative way to meet peak demands without incurring the cost of building new generation. The specific design of more conservation-oriented rates will depend, at least in part, on the procurement method chosen for post 2006 electric service. Nevertheless, it would be useful to begin the discussion now of how future rates can be crafted to further environmental objectives.

VI. Post 2006 Rate Proceeding

Proceedings to set rates for the post 2006 era will begin with the foundation laid in the workshop process. As the workshop process revealed, such proceedings will have to confront a number of ratemaking issues, some of which are traditional issues that regularly arise in rate cases and others which are unique to the post 2006 ratemaking landscape.

The RWG examined the issue of future proceedings and reached consensus that the decision to initiate a rate proceeding prior to 2007 should remain with the utilities; the Commission should not initiate rate proceedings. However, the RWG acknowledged the importance of orderly and timely implementation of post-transition period changes in rates, and encourages utilities to file rates relating to the procurement scenario(s) chosen on a timeframe that allows for orderly implementation of the scenario(s) for customers, utilities, and the Commission.

Staff recommends that the Commission ensure orderly and timely implementation by employing the traditional eleven-month schedule to conduct a rate proceeding on post 2006 issues. This schedule is necessary to allow all parties sufficient time to address the attendant ratemaking issues. Any less time would adversely impact the quality of the results achieved.

VII. Summary of Staff Recommendations

Staff's key recommendations concerning post 2006 rates are as follows:

- The Commission should adopt the RWG's agreement to separately present the delivery and generation components of ratepayer bills.

- The Commission should follow the counsel of the RWG and conduct a single proceeding to determine a common delivery service rate for both

bundled and unbundled customers for each utility in the post 2006 era. Those rates will foster competition and streamline the regulatory process. This should be implemented within the next electric rate case for each utility.

- Staff recommends that the Commission continue to employ the cost-based ratemaking approach to the delivery component of bundled rates that it developed and refined in the previous delivery service proceedings.

- For the power and energy component of bundled service, the Commission should apportion auction prices to ratepayers according to their respective load factors and/or to other load characteristics to reflect the differing contributions of customers to costs.

- The Commission should examine whether larger customers would be better served by having fixed rather than hourly prices. Furthermore, if an hourly price plan is adopted, Staff recommends the Commission consider limiting that plan to only the largest utility customers, perhaps in the 3 MW and above range.

- The Commission should examine whether a monthly true-up is necessary or whether utilities should absorb surpluses or shortfalls that result from an auction process.

- The Commission should continue to make utility tariffs and ratemaking approaches more uniform. Within the next electric rate case for each utility, Staff will make recommendations to make tariffs and rate structures more uniform.

- The Commission should follow a policy on renewable energy that is consistent with the consensus positions of the RWG. The Commission should also approve rates that promote efficient conservation of energy.

- The regulatory process is best served by implementing full eleven-month proceedings to address the critical post 2006 rate issues.

Competitive Issues

I. Introduction

The questions posed by the Commission to the Competitive Working Group ("CWG") asked whether initiatives should be undertaken to enhance competition in the areas where competition has already established a foothold and whether to implement policies to jumpstart competition in the service areas and markets where it has not yet begun. These are not new questions. The Commission has considered them in several dockets and in the many reports concerning the state of competition that it has submitted to the General Assembly. The Commission, for example, has adopted Affiliate[8] and Functional Separation/Integrated Distribution Rules,[9] has provided an opportunity for customers to obtain stable transition charges, and has initiated a proceeding intended to increase the amount of uniformity in utility tariffs.

In addition to the thirteen questions from the Commission's list, the CWG decided to form five subgroups to examine specific competitive topics suggested by members of the main working group. With the exception of the subgroup that focused on wholesale matters, the topics considered by the subgroups primarily concerned issues that affect retail competition in Illinois. The recommendations that these subgroups formulated are generally not strictly related to post 2006 issues (although competitive issues are certainly intertwined with post 2006 issues) and probably could be implemented at any time.

This section of the report considers the prospects for competition in both the residential and non-residential markets. This section also evaluates policies to stimulate retail competition and makes recommendations that are designed to interest both customers and suppliers in customer choice.

II. Status of and Prospects for Residential Retail Competition

As is by now well known, retail competition has not yet begun in the residential market, even in the service areas where a significant number of non-residential customers have switched. Moreover, after five years of customer choice, no alternative supplier has even applied for certification to serve residential customers. While Staff did not expect alternative suppliers to sell to Illinois residential customers before establishing a foothold in the large customer sector, it was hoped that alternative suppliers eventually would market to residential customers by bundling electricity with other products (e.g., natural gas) or by offering creative pricing plans. This simply has not happened and there is a considerable debate as to whether residential competition will ever take hold in the State.

[8] 83 Illinois Administrative Code Part 450 Non-Discrimination In Affiliate Transactions For Electric Utilities.
[9] 83 Illinois Administrative Code Part 452 Standards Of Conduct And Functional Separation.

One primary issue is whether residential competition is compatible with an electricity procurement strategy in which utilities hold auctions or use other competitive acquisition methods to purchase electricity on behalf of customers that do not choose alternative suppliers. One view is that residential competition will ultimately not be viable in such an environment. According to this view, very few, if any, suppliers will be willing to invest time and resources to acquire customers when the auction will produce competitive prices that will be extremely difficult to beat on a year-in, year-out basis. Residential customers will receive the majority of the benefits that can be obtained from a competitive wholesale market, leaving little room for marketers.

The evidence from the few states that have some form of standard offer services does not give rise to optimism that residential competition will be compatible with competitive procurement methods. New Jersey, which is generally cited as a potential model for Illinois, since its four utilities essentially purchase all their electricity requirements from the wholesale market, has held procurement auctions since 2002. In that year, 6,151 residential customers were taking competitive service.[10] By August 2004, however, only 1,514 residential customers were taking service from competitive suppliers.[11] The switching numbers from Maine, which has held auctions since 2001, are only slightly more encouraging. Less than one percent of residential customers have switched in the service areas of two of its three utilities.[12] However, there is one outlier among the states that have turned to auctions. One large Maryland utility, Potomac Electric Power ("Pepco"), has seen considerable switching among residential customers (about 10% of residential customers have switched), although residential customer switching levels are negligible among Maryland's other utilities.[13] While Staff does not know why switching has been markedly more pronounced at Pepco versus the other Maryland utilities, one of the reasons may be that alternative suppliers are offering services generally not available from Pepco, including a "green power" option, which may have attracted many of the customers in Pepco's service territory.

On the other hand, there are several reasons to believe that some enterprising suppliers might become interested in the residential market after 2006, especially if measures are taken to stimulate the market. First, the bundled rate freeze (which has been in effect since 1997) terminates and rates will likely follow market trends. Marketers will find it easier to compete against contemporary market-based prices than pre-1997 cost-based prices. Second, in an auction procurement scenario, residential prices might change rather infrequently, which could give marketers an opportunity to beat the utility's rates when the market price declines. Third, the

[10] Energy Information Administration, Table 9, Utility Retail Sales Statistics, 2002, Energy Information Administration/State Electricity Profiles 2002, at http://www.eia.doe.gov/cneaf/electricity/st_profiles/toc.html.
[11] "New Jersey Electric Statistics," August 13, 2004, on the New Jersey Board of Public Utilities website at http://www.bpu.state.nj.us/energy/elecSwitchData.shtml.
[12] Various tables on the Maine Public Utilities Commission website at http://www.state.me.us/mpuc/electric%20restructuring/migrationrates.htm.
[13] "Electric Choice Monthly Enrollment Report," August 2004, at http://www.psc.state.md.us/psc/.

absence of transition charges should increase customer and supplier interest in delivery services because customers will not be charged additional fees for switching. Fourth, implementation of the Rates Working Group agreement that customer rates will be unbundled will make it easier for customers to compare a marketer's offer to the utility's generation charges.

A. Potential Measures to Interest Suppliers in Serving Residential Customers

Whether residential competition can even begin entirely depends upon the Commission granting certificates for at least a small number of suppliers capable of serving a significant number of customers. As noted above, no supplier has even sought certification to serve residential customers. Some means must be found to encourage suppliers to enter the market if residential competition is ever going to get off the ground. The first step should be to determine whether the reciprocity provisions of the PUA (Section 16-115(d)(5)) have by themselves extinguished any chance of residential competition. A starting point for this analysis could be the CWG consensus that the existence of these provisions has prevented at least some otherwise qualified suppliers from seeking certification from the Commission.

Other states have instituted large-scale programs that have attracted qualified suppliers because these programs enable suppliers to drastically reduce customer acquisition costs, which are significantly higher for small-volume customers than for larger customers. Two types of such large-scale programs are known as "municipal aggregation" and "block-bidding". Under municipal aggregation, each residential and business customer of a municipality switches to a supplier chosen by the municipality's elected officials unless a customer takes some action to switch to another supplier (or the utility). Municipal aggregation is a feature of retail competition in Ohio, where some 900,000 customers have switched to alternative suppliers under such programs.[14] The Commission has studied the potential for municipal aggregation to reduce a municipality's electric costs, and concluded in a report to the General Assembly that, at least under some circumstances, such programs can result in customer benefits.[15] The report cautions, however, that the benefits could be diminished if the local utility were also to procure its power and energy predominantly from the wholesale market.[16] Also, based on its reading of Section 16-115A(b) of the PUA and Section 2EE of the Consumer Fraud and Deceptive Business Practices Act (815 ILCS 505/2EE), Staff believes that legislation would be needed to allow a municipality's governing officials to choose the municipality's electric supplier.

[14] See Ohio aggregation switching information at http://www.puc.state.oh.us/Puco/StatisticalReports/Report.cfm?doc_id=1200

[15] "Municipal Aggregation In Illinois: An Estimate of the Potential Costs and Savings from Municipal Aggregation for Selected Illinois Communities," A Report To The Illinois General Assembly, Prepared By The Illinois Commerce Commission With Assistance From The Center For Neighborhood Technology/ Community Energy Cooperative, February 27, 2003.

[16] The consensus of the Competitive Working Group is that municipal aggregation would not be likely to bring substantial benefits under most procurement scenarios.

Under block bidding programs, which have been used in other states, most notably Pennsylvania, suppliers bid to acquire large blocks of customers whom they would serve at a fixed price for a limited period, such as one year. In Pennsylvania, this policy was at least temporarily successful in moving a significant number of customers from bundled service to competitive suppliers. However, there seems to be little interest in Illinois in this policy at present.

The most useful information about the potential for residential competition might come from examining the experience in other states and from the residential natural gas choice programs in Illinois. As noted above, there is relatively little information from other states that might be directly transferable to Illinois, and, except for one utility in Maryland, the information that is available is not especially encouraging. However, the natural gas small-customer choice programs operating in the Nicor Gas and Peoples Energy service territories tell a somewhat different story. Over 200,000 residential customers have switched to gas suppliers certified to serve small-volume customers, known as Alternative Retail Gas Suppliers ("ARGS"), so there must be some interest among suppliers in serving smaller-use customers.[17]

Several characteristics of the natural gas choice programs that seem to have attracted ARGS to the small-volume natural gas market may be applicable to the small-volume electric market. First, the wholesale natural gas market is highly competitive, and suppliers can be assured that they can transport gas from the wholesale market through the interstate pipeline system and local distribution systems to retail customers. With the advent of Regional Transmission Organizations ("RTOs"), securing electricity from the wholesale market probably should not be a major concern to prospective suppliers, although transmission issues may still be problematic in some areas. Second, natural gas utilities offer billing services for ARGS, which the majority of the ARGS utilize. The fact that electric utilities do not offer these services is likely a factor discouraging suppliers from entering the market. Third, ARGS are able to use several different marketing and enrollment methods. In particular, at least some ARGS rely heavily on telemarketing. However, the Commission determined in 2003 that the PUA does not permit retail electric suppliers to enroll customers over the telephone unless the customers also sign contracts (either electronically or through a written signature). In its 2002 Competition Report to the General Assembly, the Commission advocated a modification of the PUA to permit electric suppliers to use telemarketing-based customer enrollment methods.[18] The Commission explained in its Report that utilization of this enrollment method could stimulate supplier interest in the residential market. Fourth, while prospective suppliers must obtain certification from the Commission to serve small-use customers, neither the

[17] See, "Annual Report on the Development of Natural Gas Markets in Illinois," July 2004, available on the Commission website at http://www.icc.state.il.us/ng/library.aspx?key=Natural%20Gas&key=Report.

[18] See, "Assessment Of Competition In The Illinois Electric Industry: Findings And Recommendations," January 2003, available on the Commission website at http://www.icc.state.il.us/ec/library.aspx?key=GA%20Report.

Commission's certification rules[19] nor the PUA contains reciprocity requirements applicable to ARGS.

B. Potential Measures to Interest Residential Customers in Customer Choice

Policies intended to interest customers in switching that have been suggested could be implemented through the Commission's ratemaking authority. These measures would have the effect of providing alternative suppliers an opportunity to provide different pricing plans than would be offered under the standard utility rate. For example, the Commission could vigorously implement seasonal pricing, where rates are higher during the summer than in other periods. Customers seeking more stable rates would be encouraged to switch to the alternative suppliers offering such rate plans. Or, the Commission could eliminate declining block rates to reduce the incentive for relatively large-volume residential customers to remain on utility service. Alternatively, some states have apparently purposely set rates at a level higher than the utility's actual procurement costs to provide an incentive for customers to seek alternative suppliers. However, Staff would not support any such policy that increases ratepayer utility bills solely for the purpose of encouraging customers to switch to alternative suppliers. Staff views competition as a means to increase efficiency and lower costs to customers, and not as an end in itself. Creating competition by artificially raising the cost of utility services is anathema to this principle.

It should be noted that even if suppliers become interested in the market, it is unknown whether residential customers will have an interest in switching away from bundled electric service. Staff is unaware of surveys or other similar information that might shed some light on this question.

C. Other Discussions of Residential Retail Competition

In addition to discussions by a Switching Process Subgroup (see page 45, below), the full Competitive Working Group discussed various options to stimulate residential competition. While it could not achieve consensus on the best option, it described various options put forth by members of the group. Its "Option A" consists of a number of suggestions that Staff supports. The suggestions avoid large-scale programs and instead focus on smaller-scope policies.

The Option A suggestions are: (1) maximum practicable freedom of migration away from and back to utility service, while avoiding shifting costs to non-migrating customers; (2) avoidance of punitive exit or return conditions; (3) maximum practicable opportunity for aggregation of such customers and load, including reasonable opportunities for aggregation within multi-tenant buildings; (4) reliance on market based pricing for utility provided energy services that will obviate any need for headroom adders; and (5) disaggregation of rate elements to facilitate comparison shopping.

[19] 83 Illinois Administrative Code Part 551 "Certification of Alternative Gas Suppliers."

The first two suggestions concern the ability of customers to switch to and from the utility and alternative suppliers with minimal restrictions, as long as costs are not shifted to customers that have not switched. Residential customers should be permitted to switch between alternative suppliers and utilities, without minimum stay provisions or return fees. Returning customers should pay the same rate as other residential customers. Until residential customers begin to switch in large numbers, residential switching will not measurably impose costs on non-switching customers.[20] The third suggestion would encourage self-aggregation to permit landlords to purchase electricity on behalf of their tenants.[21] The fourth suggestion is a reflection of the expectation that rates for all utilities, except for perhaps the companies that still own generation resources, will be based on market prices rather than on traditional cost-based methods. It also implies that the Commission should not purposely add extra costs to the basic generation rate in an effort to encourage customers to switch to alternative suppliers. The fifth suggestion is a statement of the agreement that customer rates should be unbundled to enable customers to compare the utility's generation rate against marketers' offers.

Eventually a determination will have to be made as to whether residential electric choice is viable in Illinois. This assessment should probably wait until after the transition period ends, when delivery service customers will no longer face transition charges, and should also wait until there has been some experience with post 2006 procurement processes. In the meantime, Staff recommends a cautious approach. The Commission should avoid adopting costly or drastic residential market stimulus measures. In particular, rate structures that intentionally set residential rates at levels that are higher than justified by cost-of-service principles should not be adopted. Rather, the Commission and the General Assembly should remove barriers to entry where they can be identified and be receptive to suggestions from customers and potential suppliers regarding improvements to the market.

If it is determined that residential choice will simply not be viable in Illinois, but there is a perceived demand for non-traditional services and pricing options, consideration should be given to requiring utilities to provide these services and options. For example, one policy that could be easily implemented would be to allow residential customers to become eligible for the real-time tariffs applicable to non-residential customers. While any customer that would take advantage of such a tariff would incur costs to purchase or lease new interval meters, a small segment of customers might nevertheless find that they could save money by paying the real-time (or day-ahead) electricity rate rather than the standard rate.

[20] The PUA allows utilities to require customers who switch back to utility service to remain with the utility for up to 24 months (Section 16-103(d)). This provision should be repealed.
[21] This policy might need legislative changes, because most landlords would need ARES certification to resell electricity.

III. Status of and Prospects for Non-residential Retail Competition

Retail competition, as measured by the number of non-residential customers switching to alternative suppliers and the number of suppliers operating in each service area, has taken hold, to a lesser or greater degree, only in the AmerenCILCO, AmerenCIPS, AmerenIP, and ComEd service areas. Switching activity has been mainly confined to the largest customers of the State's largest utilities. Very few, if any, customers have switched in any of the smaller service areas. The tables below show the growth in switching to alternative suppliers among non-residential customers since 2000 and the number of suppliers operating in each territory.

As the first table indicates, the number of customers purchasing power and energy from alternative electric suppliers rather than ComEd has consistently increased since 2000, although the growth rate seems to be leveling off. In the downstate areas, switching started relatively slowly, dropped precipitously, and has only recently increased. The recent growth in activity appears to be due to new marketing efforts of suppliers unaffiliated with the downstate utilities that had previously been operating in the ComEd service area only.

Retail Customers Served by Alternative Electric Suppliers (2000-2004)[22]

Utility / Year	2000	2001	2002	2003	2004
CIPS	87	671	193	512	485
ComEd	6,295	8,025	12,507	10,347	10,339
Illinois Power	556	22	18	35	75
CILCO[23]	see footnote				
All Others	0	0	0	2	0

As the next table shows, the number of alternative suppliers making sales in each service territory has remained fairly constant since 2000. However, some of the suppliers in the Ameren areas have only a small number of customers.

Number of Active Retail Electric Suppliers (2000-2004)

Utility / Year	2000	2001	2002	2003	2004
CIPS	3	2	4	5	4
ComEd	8	7	8	8	7
Illinois Power	4	3	4	3	3
CILCO[24]	see footnote				
All Others	1	1	0	2	1

[22] Year-end data for 2000-2003 and as of August for 2004.
[23] Data does not include AmerenCILCO due to confidentiality concerns (see Docket No. 03-0712).
[24] Data does not include AmerenCILCO due to confidentiality concerns (see Docket No. 03-0712).

Despite the uneven market development, it is clear from an examination of the switching statistics available on the Commission website that a substantial fraction of the largest Illinois customers, at least, has expressed an interest in switching away from basic utility service. About 37% of all non-residential customers over one MW in demand have switched to alternative supplier service and another 21% of these customers have switched from bundled service to Power Purchase Option ("PPO") service. Thus, over one-half of non-residential customers with a demand exceeding one MW are now taking delivery service. In contrast, only about 4% of all customers with a demand less than one MW are taking delivery service.[25]

Given the interest in delivery service, at least among the largest customers, the basic competitive questions concern whether this momentum can be sustained when the transition period comes to a close at the end of 2006. There is reason to believe that it can. Transition charges will no longer be imposed after 2007, creating new savings opportunities for customers. Illinois utilities' membership in Regional Transmission Organizations ("RTOs")[26], even though certain "seams" issues and other matters are not yet resolved, are expected to increase the competitiveness of the wholesale market. The Commission's Integrated Distribution Companies ("IDC") rule[27] prohibits utilities from enticing customers to remain on utility service by offering discounted rates, and seems to have resulted in customer movement from utility service to alternative suppliers. The recent interest among non-affiliated suppliers in the downstate areas may indicate that retail competition can finally begin to take hold in the Ameren service areas.

However, there are almost an equal number of reasons to be skeptical about the prospects for continued growth in retail competition. First, in large part, the growth in delivery services has been sustained by the availability of PPO service. Somewhat unexpectedly, PPO service has played an important role in the retail electric market. The existence of the PPO option enabled most customers in the service areas in which utilities chose to impose transition charges to obtain a discount from the bundled rate without stepping too deeply into the competitive market. As a result of the easy availability of the PPO, thousands of customers switched away from bundled service. In the downstate service areas, where alternative supplier options are not nearly as plentiful as in the ComEd service area, the PPO has been especially attractive to customers. In the AmerenIP market, for example, about 93% of AmerenIP's approximately 1,100 delivery services customers have switched to the PPO. It remains to be seen whether PPO customers will be as eager to switch to alternative supplier service when PPO service is no longer available in 2007 in its present form. After AmerenCIPS suspended its transition charge, making the PPO no longer available in that service territory, hundreds of former AmerenCIPS alternative supplier customers returned to bundled service, where many have remained.

[25] Electric switching statistics are available on the Commission website at http://www.icc.state.il.us/ec/switchstats.aspx.
[26] For purposes of this report, the concepts of RTOs (regional transmission organizations) and ISOs (independent system operators) are basically the same.
[27] 83 Illinois Administrative Code Part 452 Standard of Conduct and Functional Separation

Second, there is simply a lot of inertia to overcome. It is possible that the majority of customers who want to switch to delivery services have already done so. For instance, while customers can easily sign up for the PPO and save money, only a minority of customers has taken advantage of the opportunity. This may indicate that some customers may simply not bother to switch, even if switching might seem to be in their financial self-interest. Another sign of the flattening of interest in delivery services is that switching is correlated with customer size. As noted above, as customer size decreases, the percentage of customers who have switched also decreases. At the extreme, none of the State's smallest customers (residential customers) have switched, while a majority of the State's largest customers have switched.

Third, the arguments above discussing the possibility that the utilities' competitive procurement processes may leave only a small amount of room for marketers to beat standard utility rates may also apply to some extent to the non-residential market. In New Jersey, this problem was addressed in part by requiring the largest customers to pay spot market prices if they wished to take bundled service from the local utility. However, Staff is reluctant to recommend that utilities offer only hourly rates to their largest customers.

Fourth, as noted above, there is agreement that the reciprocity requirements have restricted the number of qualified suppliers that serve retail customers. The problem that this creates appears especially acute outside of the ComEd service territory. As shown above, only a few major suppliers are currently operating in the Ameren areas, and among the most successful of these suppliers are affiliates of the incumbent utilities.

IV. Competitive Declaration Petitions

The CWG discussed issues related to competitive declaration petitions filed under Sec. 16-113. While there was no consensus as to whether Sec. 16-113 should be modified or deleted, it is clear that a large number of participants believe that the relevance of Sec. 16-113 should be reexamined in light of the selection by the State's largest utilities of IDC status. A utility organized as an IDC functions primarily as the distributor of electricity purchased from third parties and is essentially prohibited from competing for customers through the offering of discounted rates or other inducements. An argument might be made that, even though a utility cannot attempt to retain its customers, it still has responsibility for procuring electricity for them upon demand. However, this argument would bear little weight in the context of an auction procurement method because utilities would likely bear very little, if any, supply risk. Staff suggests that Commission recommend modifying Sec. 16-113 to permit the Commission to set the standards by which a competitive declaration should be evaluated.

V. Subgroup Discussions

In the process of discussing the questions posed by the Commission, the Competitive Working Group created five subgroups to examine competitive issues not directly referenced in the Commission's questions. The ARES Certification, Licensure and Tariffs Subgroup examined issues of concern to alternative suppliers, especially the fundamental issue of certification rules. The Customer Information and Data Flow Subgroup and the Billing, EDC Charges, SBO, Timing, and Consolidated Billing Subgroup reviewed operational issues, including billing and electronic data transfer issues. The Wholesale and Transmission Subgroup primarily looked at issues connected with RTO development. Finally, the Switching Process Subgroup reviewed issues primarily from a customer perspective.

A. ARES Certification, Licensure and Tariffs Subgroup

The ARES Certification, Licensure and Tariffs Subgroup took an extensive look at Part 451, the Commission's rule pertaining to the certification of Alternative Retail Electric Suppliers ("ARES").[28] It contains the standards and requirements that prospective suppliers must meet to obtain certification to sell power and energy to retail customers. The standards include provisions relating to technical, financial and managerial qualifications. The rule was first adopted in 1999 and was revised in 2000 and 2002. The subgroup concluded that various rule provisions should be reviewed for possible modification. Staff does not oppose opening a proceeding for that purpose. The proceeding should take into account the consensus items reached in the workgroup discussions. Additionally, all parties should be permitted to recommend modifications to the rule.

The subgroup engaged in an extensive discussion of Sec. 16-115(d)(5), the "reciprocity requirements" of the PUA. While there was certainly no consensus as to whether these provisions should be modified or deleted, the subgroup did achieve consensus that the provisions have limited the number of ARES that can operate in Illinois. Staff agrees with this assessment. The competitive issue associated with reciprocity is whether the restriction on the ability of otherwise qualified suppliers to enter the market has stunted the growth of retail competition. A strong case can be made that, at least in the downstate areas, the establishment of retail competition has become significantly more difficult because of the existence of the reciprocity requirements. Customers in these areas plainly are interested in switching away from traditional bundled service, but the majority of customers who have switched have chosen PPO service rather than service directly from alternative suppliers. In the AmerenIP service area, for example, more than 1,000 customers are taking PPO service, while only about 75 are taking service from alternative suppliers. In the AmerenCIPS service territory, several hundred customers switched to PPO service, as well. However, when the company suspended its transition charges (and thus was no longer required to offer the PPO), most of those customers were forced to return to bundled service, because

[28] 83 Illinois Administrative Code Part 451 Certification of Alternative Retail Electric Suppliers

few alternative suppliers were available to serve them on an unbundled basis. Presumably, there would be more switching to alternative suppliers, if only more alternative suppliers could legally obtain certification.

Of course, it is possible that other factors--such as the terms and conditions associated with transmission service, or comparatively low bundled rates--have prevented or discouraged authorized suppliers from successfully entering the downstate markets. Nonetheless, limiting the pool of potential suppliers cannot possibly enhance the level of competition and may even have stunted its growth, to date. Given the existence of the reciprocity restrictions, the best that can be expected for retail competition in the downstate markets is that existing suppliers in Northern Illinois will turn some of their attention southward. Recently, this has begun to occur, but still, alternative suppliers are serving only minuscule portions of eligible customers.

The subgroup discussed "registration" requirements, the utility-imposed requirements that become applicable to alternative suppliers after certification and enable alternative suppliers to conduct business in a utility's service territory. The requirements primarily consist of various contracts governing the relationship between the utilities and alternative suppliers. According to the subgroup, each utility's requirements and contracts are not identical, which potentially could impose costs on alternative suppliers trying to market in more than one service territory. The subgroup could not agree that the requirements should be identical and left the goal of uniformity as an "aspiration." Staff recommends that the Commission encourage utilities to reduce the amount of dissimilarity in these requirements when appropriate. In particular, the Ameren companies should strive to eliminate differing registration requirements in their service territories.

The subgroup also looked at so-called "agency" issues. Agents are companies or individuals that represent customers in energy matters, and provide such services as consulting and billing. Agents are generally, but not always, alternative suppliers. The subgroup concluded that agents do not provide regulated services (except to the extent that they are also engaging in conduct that makes them alternative retail electric suppliers under the PUA Section 16-102 definition of that term) and should not be regulated by the Commission. Staff has examined this issue in the past and reached the same conclusion.

Utilities require evidence, such as signed documentation, from agents regarding their relationship with their customers. There was a suggestion that any such documentation be standardized and easily obtainable. Staff agrees that utilities should set as a goal the standardization of agency documentation.

B. Customer Information and Data Flow Subgroup

The Customer Information and Data Flow Subgroup took as its charge an assessment of the need to further standardize the codes and data fields used to send electronic information between alternative suppliers and utilities. The

subgroup concluded that a forum should be created to allow market participants to regularly meet to discuss transaction-related issues. The subgroup recommended that the Commission facilitate these meetings through the use of the Commission's website. Staff believes that the Commission's website could be used for this purpose. The subgroup also recommended that any conclusions reached by a working group evaluating proposed electronic data transfer proposals that result in changes that are implemented by utilities be recoverable in utility rates. While Staff believes that the efforts of the working group could eventually result in enhanced efficiency and lower costs, Staff cannot support this recommendation if it is intended that a rider mechanism, or some similar mechanism, be used to recover expenditures recommended by the working group.

C. Billing, EDC Charges, SBO, Timing, and Consolidated Billing Subgroup

The Billing, EDC Charges, SBO, Timing, and Consolidated Billing Subgroup focused on customer billing issues, especially issues connected with the Single Billing Option. The subgroup concluded that these issues could be addressed in a future uniformity initiative. There appears to be some potential for single billing and similar issues to be discussed in the working group formed to promote uniformity in electronic data transfer.

D. Wholesale and Transmission Subgroup

The Wholesale and Transmission Subgroup examined a number of issues connected with the operation of the wholesale electricity market. The subgroup attempted to determine what policies the Commission should pursue to improve the competitiveness of the wholesale market through its advocacy efforts at the Federal or regional levels. The subgroup concluded that the Commission should promote policies intended to enhance customer choice while also protecting Illinois ratepayers. The subgroup offered a listing of the types of such policies. These include the following:

(a) monitoring of areas in Illinois where ownership of generating capacity is highly concentrated, to ensure that the increased competitiveness of those markets that is anticipated (with AEP's entry into PJM) actually occurs;

(b) supporting PJM's efforts to revise its capacity construct to assure better overall system reliability and encouraging MISO to adopt a similar capacity construct;

(c) monitoring the application and hedging of congestion costs in Illinois control areas subject to Locational Marginal Pricing (LMP) and Financial Transmission Rights (FTR) to determine if policy changes are needed to protect consumers from unhedged congestion costs;

(d) eliminating seams issues affecting the Illinois competitive market between control areas and between RTOs;

(e) creation of a functioning joint and common PJM/MISO market;

(f) appropriate transmission rate designs which do not result in inequitable or inappropriate cost shifts to Illinois consumers;

(g) development of a standardized, low cost set of interconnection rules and procedures for the interconnection and operation of small (less than 20 MW) Distributed Generation;

(h) resource adequacy rules; the conditions of obtaining Network Integration Service; and

(i) pricing of Imbalance and other Ancillary Services.

Staff agrees that these are important policy issues for Commission advocacy, and the Commission and Staff have addressed these issues, as explained below, in various forums.

First, generation concentration is an important factor in wholesale market competitive analyses and American Electric Power's participation in PJM may expand the relevant geographic market for competitive analyses. Staff has examined these issues in the context of evaluating Exelon's market-based rate application that was filed with FERC. Staff is aware that the PJM stakeholders are in the process of developing a new capacity market approach for resource adequacy purposes and has been involved in that process.

Second, Financial Transmission Rights ("FTRs") are an important hedging instrument in RTO-operated markets. Such FTRs are already facilitated within PJM, and are expected to be introduced within the Midwest ISO ("MISO") on March 1, 2005. Staff has actively participated in the RTOs' FTR allocation policy development processes and the Commission has submitted Comments to FERC on several FTR issues in the interests of Illinois. Because of the transmission owning utilities' RTO participation decisions, the MISO/PJM seam runs through Illinois. The Commission and its Staff have actively worked with the RTOs and with FERC to minimize the negative effects of this RTO seam and has urged the parties to move rapidly on development of a joint and common market that will eliminate the impacts of the seam.

Third, transmission rate design is an important issue for Commission advocacy. The Commission submitted Comments to FERC advocating a transmission cost allocation approach, across both the MISO and PJM, that incorporates the concept of regional beneficiaries contributing to cost recovery in proportion to the benefits received from transmission facilities. On generation interconnection issues, the Commission participated in MISO's process to implement FERC's rules concerning interconnection of large generators to reduce barriers to entry by new generators and to properly allocate the costs of new transmission facilities needed to interconnect new generators.

Finally, Staff has supported PJM's market development efforts for transmission ancillary services and has encouraged the MISO to develop appropriate market structures for these services.

E. Switching Process Subgroup

The Switching Process Subgroup considered the question of customer knowledge about the electric market, along with other issues. The subgroup recommends a second round of consumer education to further the program that was undertaken in 1999. The goal of the new program would be to inform customers about the changes in the industry since customer choice began, including information about the implications of the expiration of the rate freeze. Staff agrees that residential customers would benefit from a new education program. However, the question of how such a program would be funded (i.e., through an appropriation from the General Assembly or through utility rates) would need to be addressed.

The Switching Process Subgroup also considered consumer protection issues that could be important, especially if residential customers begin to switch in large numbers. The subgroup identified instances where utility tariffs and Commission rules do not reference existing consumer protection statutes, such as the Consumer Fraud and Deceptive Practices Act.[29] The subgroup recommends addressing these possible deficiencies in a future ARES certification rulemaking. The subgroup also noted that utilities could have difficulty in accommodating mass switches. The subgroup recommends revisiting this issue when residential suppliers begin to apply for certification. Staff agrees that consumer protection issues can be addressed in an ARES certification rulemaking that should be undertaken in 2005.

VI. Summary of Staff Recommendations

Staff recommends the Commission adopt or advocate a number of policies to further develop competition.

- Modify the PUA to permit electric suppliers to use telemarketing-based customer enrollment methods.
- Eliminate the authority for the 24-Month Minimum Re-enrollment Requirement in Section 16-103(d).
- If utilities use auctions to procure power and energy, permit small-use customers to move between alternative suppliers and utility service without penalty.
- Do not strongly advocate large-scale customer migration programs such as municipal aggregation or programs in which customers are transferred to alternative suppliers.

[29] 815 ILCS 505/2EE

- Modify Section 16-113 to permit the Commission to set standards for competitive declarations or delete the section.

- Open a proceeding to consider modifications to Part 451.

- Endorse the “Option A” recommendations of the Competitive Working Group, as described on page 36.

- Consider endorsing a second customer education program to inform small-use customer about recent and upcoming changes in the electric industry, if the means can be found to fund the program.

- Endorse industry participants’ interest in establishing an independent working group to promote uniformity in electronic transactions, and facilitate its efforts through the use of the Commission’s internet site for posting working group communications and reports.

- Continue to encourage additional uniformity in other areas, including customer billing issues.

Utility Service Obligations

I. Introduction

Currently, the PUA requires utilities to offer bundled services (as specified in Section 16-103 of the PUA); real-time pricing ("RTP") service (as defined in Section 16-107); and, PPO service to non-residential customers (as defined in Section 16-110), if transition charges are imposed on customers who take delivery services.[30] The utilities' obligation to provide bundled services and RTP will remain after 2006; however, their obligation to provide PPO service will be limited to the requirements of Section 16-110(c) and (d). These sections of the PUA appear to limit eligibility for PPO service to only those customers who paid transition charges during the Mandatory Transition Period.

The starting point for discussions by the Utility Service Obligations Working Group ("USOWG") was the utilities' present load-serving obligations, as generally described above. The primary focus of the group was to determine whether these obligations should remain in their present form after 2006 or whether the obligations should be changed in some manner. A related question was whether a utility could, if it wished (or if it were ordered to do so), be relieved of these obligations.

In certain circumstances, and with Commission approval, utilities may be relieved of their obligation to provide bundled services. A utility may file a petition under Section 8-508 to abandon a service, or file a petition under Section 16-113 seeking a declaration to have bundled service declared competitive for a specific customer class. In the latter circumstance, after a service is declared competitive, the utility will have only a limited obligation to provide bundled service to the customers in the competitive group and only to those customers who are taking bundled service at the time of the competitive declaration. Also, Section 16-113 specifies that utilities may not file a petition to declare residential and small commercial ("small-use") service competitive until the end of the Mandatory Transition Period.

The USOWG determined that it would be useful to look at potential changes to these obligations from the perspective of three customer groups: (1) small-use customers; (2) large-use customers (customers with over 15,000 kWh annual usage) for whom a competitive declaration has not been approved; and (3) competitive large-use customers.[31]

[30] Section 16-103(e) also provides that "The Commission shall not require an electric utility to offer any tariffed service other than the services required by this Section, and shall not require an electric utility to offer any competitive service." 220 ILCS 5/16-103(e).

[31] Only one competitive declaration petition has been submitted to the Commission. The Commission granted ComEd's petition to have service offered to customers with a demand greater than 3 MW declared competitive.

II. Small-Use Customers

The USOWG decided that the utilities' obligation to provide power and energy services to small-use customers should not change after 2006. Staff agrees. Residential customers and the vast majority of small-commercial customers are entirely dependent on the incumbent utility for their generation services. As noted elsewhere in this report, no alternative suppliers are serving the residential market, and the prospects for a competitive residential market are negligible. The Commission and the General Assembly should not act to disturb the utilities' obligation to provide generation services to all residential (or small commercial) customers until it is definitively shown that another entity can provide those services essentially in the same fashion and within the same legal responsibilities as utilities. The USOWG concluded that any entity that does take on responsibility for providing bundled service should be regulated as a public utility.

III. Large-Use Customers That Have Not Been Declared Competitive

The second customer group that the USOWG reviewed with respect to utility service obligations consists of non-residential customers whose service has not yet been declared competitive. Currently, this group consists of all non-residential (with the exception of small commercial) customers for each utility except for ComEd's 3 MW and above customers. The USOWG concluded that utilities currently do and should continue to have responsibility to provide bundled service to this customer group. Staff agrees. While it might be possible to develop a model whereby responsibility for the provision of bundled service devolves to and is assumed by third-parties, there is little indication that any third-party is willing to step forward and offer comparable bundled service to all customers desiring the service.

IV. Competitive Customers

The USOWG also looked at the utility's responsibility to provide service to the customers taking service that has been declared competitive. Other than the provision of real-time pricing as required under Sections 16-107, and 16-110(c) and (d), the USOWG concluded that the only load-serving obligations that a utility has with respect to customers taking service that has been declared competitive are described in Section 16-113. Generally, Sec. 16-113 requires a utility to provide bundled service to customers for whom service has been declared competitive for three years following the competitive declaration and only to those customers who are taking bundled service at the time of the competitive declaration. There was disagreement as to whether the PUA should be changed to impose an obligation to provide a bundled or similar service on the utility or another third-party.

This issue is of paramount importance to the State's largest customers because of the nature of the competitive standards listed in Section 16-113 that a utility must meet in order to obtain a competitive declaration from the Commission. These standards are not as stringent as the standards that many parties to the USOWG discussions might propose, and the Commission might develop, if the Commission

were permitted to determine the competitiveness of a service, independent of the language in Section 16-113. It is also fair to say that the Section 16-113 standards do not give absolute assurance to customers that suppliers will always be available to offer electricity for sale on similar terms and conditions as bundled service should the service be declared competitive. The lack of such assurance is likely a contributing factor to the reluctance of customers to switch to alternative suppliers, rendering such customers ineligible for bundled service for the three-year "grace period" that exists following a competitive service declaration.

Unless Section 16-113 standards for competitive service declarations are changed, or unless there is some enhancement of the obligation to provide electricity to customers within groups subject to such competitive service declarations, large customers will likely lack confidence in moving off of bundled rates because of the threat that a utility could petition the Commission to have their service declared competitive. For example, in the AmerenIP (formerly "Illinois Power") service territory, Section 16-113 arguably permits the company to declare generation service competitive for various customer groups, despite the fact that only about 75 customers have switched to alternative suppliers, to date. To better address the needs of customers during the development of the market, the Commission should seek an expansion of its authority to define the standards under which utility services may be declared competitive.

Staff also suggests that, even if Section 16-113 is not eliminated or modified, a reasonable means to address this problem could be found through the auction process if utilities were to include competitive customers in their auctions. Since a main characteristic of the typical auction process is that utilities simply pass the costs of electricity directly through to customers and recover all costs for administering the auction, it does not appear that a utility could be financially harmed by offering electricity procured through an auction to competitive customers. An ancillary benefit of this policy is that the price derived from the auction could serve as the benchmark against which a competitive customer could compare prices offered by alternative suppliers. Staff recognizes that it may be appropriate to establish terms and conditions governing the competitive customers' eligibility for auction-determined electric rates that might not be necessary for other customers, such as requiring a lengthy notice period for any customer who might wish to take service at the price determined by the auction.

V. Summary of Staff Recommendations

Staff recommends the following with respect to utility service obligation:

- Do not modify the utilities' existing service obligations to those customers whose service has not been declared competitive.

- Competitive customers should be permitted to obtain service at the fixed rates available to non-competitive customers.

- As noted above, modify Sec. 16-113 to permit the Commission to set standards for competitive declarations or delete the section.

Energy Assistance

I. Introduction

The Energy Assistance Working Group ("EAWG") focused on two major questions:

(1) How should energy assistance programs be provided for low-income customers who cannot afford to pay?

(2) Are current mechanisms adequate for funding energy assistance programs?

The EAWG found consensus on a great many points. Most of the group's recommendations may be accomplished without official Commission action. However, consensus was not reached on all issues. For instance, some committee members expressed a desire to have the Commission consider implementation of an entirely new energy assistance plan based on a percentage of income.

Perhaps the most important question underlying the entire group's discussions was whether energy assistance funding by the State, as provided for in the Electric Restructuring Act of 1997, should continue after the transition period. Section 13 of the Energy Assistance Act created the Supplemental Low-Income Energy Assistance Fund and a companion energy assistance charge to be assessed by electricity and natural gas delivery companies on their customer accounts. This section of the Act is set to expire on December 31, 2007. Currently, funding from the State's Supplemental Low-Income Energy Assistance Fund is approximately $65 million. If the funding provision is eliminated when the transition period expires, the number of low-income households receiving assistance will drop dramatically. Staff recommends that the Commission support continuation of funding through the transition, but defer to the General Assembly to determine whether the energy assistance fund should continue after December 2007.

The following sub-sections examine areas of consensus reached by members of the EAWG, including whether State funds supporting energy assistance programs should be maintained and if so at what level.

II. LIHEAP Eligibility

This year, the Illinois Department of Public Aid (IDPA) assumed responsibility for administration of the Low-Income Home Energy Assistance Program (LIHEAP) from the Department of Commerce and Economic Opportunity (DCEO). At this point, the Commission's role in the program is advisory. Staff participates in a policy advisory council comprised of representatives of utilities, State agencies and low-income household advocates. The Commission's Consumer Services Division regularly receives inquiries about energy assistance, but directs those inquiries to the local administering agency or IDPA. While the Commission does not have a direct

responsibility for implementing energy assistance programs, it has always cooperated fully with the IDPA and DCEO (and its predecessor agency) in administering these important programs.

The Energy Assistance Working Group agreed that LIHEAP has been a valuable program with a significant impact on eligible consumers. Currently, the State's definition of eligibility reflects the federal standard of income at or below 150 percent of the federal poverty level.

The EAWG and Staff concur that the limit on eligibility should remain the same. Furthermore, households with elderly or disabled members and households without energy service should continue to be eligible to apply for aid early, before the general application period begins. It was the consensus of the working group that the IDPA in consultation with the Policy Advisory Council should consider expanding that priority application eligibility period to households with incomes less than 50 percent of the federal poverty level and families with children under the age of 16.

III. Percentage of Income Payment Plan

An energy assistance plan that would base energy charges on a percentage of income was debated and the consensus of the EAWG was that it should be more fully explored by policymakers including the Illinois Commerce Commission.

Some members of the working group actively support a percentage of income plan, where eligible customers are not required to pay more than a specified percentage of their income toward energy bills. Proponents of such a plan argue that low-income families typically pay a greater percentage of their household income on energy than do the majority of Illinois families. They suggest that a properly designed percentage of income plan could make energy more affordable for LIHEAP eligible customers. Others in the EAWG could not support a plan without some assurance that energy costs would be covered.

In Staff's view, the design of a new percentage of income plan would require additional discussions concerning the specific percentage of a low-income family's income that should be dedicated to paying energy bills, who shall pay the shortfall between the full bill for utility service and the percentage-of-income bill paid by the eligible customer, and many other program details. Staff also believes that the IDPA and the Illinois General Assembly should be the leaders of any discussion on a percentage of income plan and a funding source to support such a plan.

Those who supported initiation of a percentage of income plan pointed to a former program, the Illinois Residential Affordable Payment Plan (IRAPP), which, studies show, led to a reduction in service disconnections, reduced shortfall, bad debt and collection costs, and resulted in participants paying a greater portion of their utility bills than similarly-situated non-participants. Staff notes that IRAPP was funded by disbursements made to the State of Illinois as a result of litigation alleging federal oil

price violations as determined by a court order. See United States v. Exxon Corp., 773 F.2d 1240 (Temp. Emer. Ct. App. 1985). IRAPP ended when the funds were exhausted. Proponents purport that the Commission derives authority from Section 9-244 of the PUA to adopt a percentage of income plan if one were proposed by a public gas or electric utility.[32] However, within the working group, there was not enough support for the percentage of income plan to move it to a consensus position.

Staff suggests that, if a percentage of income plan were to be implemented, the IDPA, which oversees the majority of assistance programs in the State, would be the appropriate agency to administer such a plan, with consultation from the Policy Advisory Counsel.

IV. Energy Efficiency Education Programs

The EAWG stated that energy efficiency education programs may be helpful in providing Illinois consumers with information on how to reduce energy costs, and reserved judgment until IDPA completes a pilot program on financial education and energy conservation. The group's consensus on this issue is that a pilot program may provide the evidence necessary to determine if the energy efficiency programs help LIHEAP eligible consumers reduce energy costs.

Staff notes that if energy efficiency education programs are to reach all eligible households, sufficient funding is necessary to produce the informational materials and deliver the message through the media to the targeted households.

V. Disconnection, Reconnection

The EAWG determined that the cycle of a utility disconnecting a customer in the spring or summer for non-payment and then reconnecting in the fall when LIHEAP funds become available is not in the best interest of utilities or their customers. But the group did not reach consensus on any proposal for remedial action.

Some members of the working group argued that history demonstrates the disconnection/reconnection rules are inadequate for a great number of LIHEAP recipients. The group pointed out that in recent years State officials have directed that there be voluntary reconnection programs for LIHEAP recipients that are more favorable to the customer than those provided for by Commission rules or the law. The minority position would have the General Assembly or the Commission codify these "voluntary" programs. The programs have generally been implemented late in the fall, they said, which creates uncertainty for LIHEAP recipients and utilities. The minority position suggests that low-income customers should have their heat-related utility service restored between September 1 and December 31 if they pay 20 percent of their arrearages or $250, whichever is less. Instituting this proposal

[32] Section 9-244 deals with "alternative rate regulation."

does not seem consistent with breaking the cycle of spring/summer disconnections followed by reconnection in the fall or winter.

Staff notes that current law and Commission rules provide for reconnection of eligible former customers for less than the full amount owed – 20 percent for low-income applicants. Utilities are not required to offer this option two consecutive years or if the former customer benefited from meter tampering. The minority position does not specify conditions for reconnection. Staff cautions that if heat-related service can be reconnected for a maximum of $250, LIHEAP customers could be reconnected every year, regardless of what was owed on the bill. If the customer does not pay the balance due, it is unclear who would bear the cost. And since not all low-income customers receive LIHEAP benefits due to lack of available funds, it is important to consider whether such a policy would apply only to those who receive LIHEAP funds or to all low-income customers who meet the eligibility requirements. Therefore, if the Commission determines that amendments are needed to the current disconnection and reconnection rules, Staff recommends that workshops be held to explore the issues.

VI. Supplemental Low-Income Energy Assistance Fund's Energy Assistance Charge

The Supplemental Low-Income Energy Assistance Fund derives its revenue from an account charge (sometimes referred to as a meter charge) on customer bills. Unless it is renewed by the Illinois General Assembly, this funding mechanism will expire on December 31, 2007. Staff notes that if the current funding mechanism is discontinued, a dramatic reduction in funding will result. In that case, there likely will be a need to re-examine criteria for eligibility or reduce the number of low-income households served. It appears likely that fewer low-income households will receive energy assistance funding if the State's supplemental assistance fund is eliminated. At the same time, the demand for energy assistance is likely to grow, particularly if utility rates increase after the transition period's rate freeze is lifted.

Working group members did not reach consensus that the energy assistance charge should continue after the current expiration date of December 31, 2007. Whether the fund should continue is a decision that must be made by the General Assembly. The working group determined, and Staff concurs, that the energy assistance charge should be at least maintained at current levels, if the fund is allowed to continue beyond 2007.

VII. Participation in the State Supplemental Low-Income Energy Assistance Fund by Municipal Utilities and Electric Cooperatives

No consensus was reached on whether municipal utilities and electric cooperatives should be required to participate in the State Supplemental Low-Income Energy Assistance Fund. The Customer Choice and Rate Relief Law of 1997 created the fund and allowed, but did not require, municipal utilities and cooperatives to participate through the meter charge discussed in the previous section. However,

customers of municipal or cooperative utilities that do not participate are not eligible to receive these supplemental funds.

A concern, expressed by some members of the EAWG was that in areas served by municipal utilities or rural electric cooperatives that chose not to participate in the Supplemental Low-Income Energy Assistance Fund, low-income customers may be at a disadvantage.

Staff offers no recommendations on this issue.

VIII. Administrative Code Changes

The EAWG generally agreed that the Post 2006 initiative was not the appropriate forum to explore changes to the administrative code, particularly to Part 280, which establishes procedures for gas, electric, water and sanitary sewer utilities pertaining to eligibility for service, deposits, payment practices, discontinuance of service, and complaint procedures. Therefore, the working group made no recommendations for modifying the administrative code. Nevertheless, some participants did express interest in making rule changes pertaining to low-income customer issues.

Of the topics raised was the concept of “can’t pay” versus “won’t pay.” Working group participants did not reach consensus on a practical definition of these terms, nor was there consensus on how such a distinction between “won’t pay” and “can’t pay” could be embodied within code Part 280 or other Commission rules.

Some participants suggested the administrative code could be modified to benefit low-income customers. However, the EAWG did not reach consensus that the code should be changed for this purpose. Staff notes that Part 280 currently offers low-income customers more lenient provisions with regard to payment arrangements, disconnection, and reconnection. Revisions to such provisions may be appropriate. However, in Staff’s view, Part 280 is the wrong tool for directly making energy more affordable for low-income customers.

IX. Summary of Staff Recommendations

Staff’s recommendations concerning energy assistance programs are as follows:

- If the current level of funding is maintained, eligibility for the Low Income Home Energy Assistance Program should remain the same (150 percent of federal non-farm poverty level), and households with elderly or disabled persons should be offered a priority application period.

- The Illinois Department of Public Aid would be the proper agency to lead the discussion on development of a percentage of income plan.

- If the Commission determines amendments are needed to current disconnection, reconnection rules in order to halt the cycle of utility

disconnections in the spring and summer, followed by reconnection in the fall and winter, workshops would allow parties to work out details to provide a system that is fair to all low-income customers.

- The Commission should defer to the General Assembly to decide whether the energy assistance fund should continue after December 2007.

Implementation

The Implementation Working Group ("IWG") was assigned the task of examining the reports of the five working groups, Energy Assistance, Utility Service Obligations, Rates, Competitive Issues, and Procurement, to determine how consensus items and significant non-consensus issues could be implemented. The IWG was composed of the conveners of the five working groups and the Office of General Counsel.

Generally speaking, IWG undertook the following process: Each working group convener prepared an initial implementation draft report of his or her respective working group. In most instances, the review considered the questions originally posed in Staff's White Paper, together with consensus items and significant issues on which consensus could not be reached. That initial draft was then made available to all participants of the respective working group for comment. Any comments received by the convener were then incorporated into a final draft report. The final draft implementation report of the five conveners was again circulated among the respective working group participants for final review and comment. To the extent time permitted, any final comments received were incorporated into each group's final implementation report, which was forwarded to the IWG convener. Upon receipt of each of the five implementation reports, the Office of General Counsel provided its comments to the proposed implementation methods. The compilation of these documents, including the OGC comments, is the substance of the IWG Report, which is being provided to the Commission under separate cover.

Appendix 1: Working Group Final Reports